California ISO
Your Link to Power

ISO Study of Operational Requirements and Market Impacts at 33% RPS

Continued Assessment of Statistical Model (Step 1)

and

Selected Production Simulation (Step 2) Results available as of November 29, 2010

Presentation Slides

CPUC Workshop on

CAISO and PG&E Renewable Integration Model Methodologies

November 30, 2010

SECTION 1: INTRODUCTION AND OVERALL STATUS

Contents of Presentation

Objectives

1. Identify operational requirements and resource options to reliably operate the ISO controlled grid (with some assumptions about renewable integration by other Balancing Authorities) under 20% to 33% RPS in 2020
   - Estimates of operational requirements for renewable integration (measured in terms of operational ramp, load following and Regulation capacity and ramp rates, as well as additional capacity to resolve operational violations)
   - Consideration of additional variables that affect the results
     - Impact of different mixes of renewable technologies and other complementary policies
     - Impact of forecasting error and variability

Objectives (cont.)

2. Inform market, planning, and policy/regulatory decisions by the ISO, State agencies, market participants and other stakeholders
   - Support the CPUC to identify long-term procurement planning needs, costs and options
   - Inform other CPUC, and other State agency, regulatory decisions (Resource Adequacy, RPS rules, once through cooling (OTC) schedule, and so on)
   - Inform ISO and state-wide transmission planning needs to interconnect renewables up to 33% RPS
   - Inform design of ISO wholesale markets for energy and ancillary services to facilitate provision of integration capabilities

Study approach – overview of modeling tools utilized and proposed for LTPP methodology

- *Step 1* – Statistical Simulation to Assess Intra-Hour Operational Requirements
  - Estimates added intra-hour requirements under each studied renewable portfolio due to variability and forecast error
  - Calculates the following by hour and season: Regulation Up and Regulation Down capacity, load-following up and down capacity requirements, and operational ramp rate requirements
- *Step 2* – Production Simulation
  - Dynamic optimization model that simulates system least-cost commitment and dispatch of resources to meet load, ancillary services and other requirements in an hourly time-step.
  - Uses Step 1 Regulation and load following capacity requirements to reflect intra-hourly operations
  - Calculates production cost-based energy prices, emissions, energy and ancillary services provided by units, violations of system constraints and add’l capabilities required to eliminate violations

Progress on recent ISO and related California renewable integration studies

Study results	Date (2010)
CEC/KEMA , Research Evaluation of Wind Generation, Solar Generation and Storage Impact on California Grid	June
CPUC workshop: ISO 33% RPS study methodology and Step 1 results/PGE methodology and results	August 24-25
ISO 20% RPS study	August 31
ISO stakeholder meeting on 20% RPS study	September 17
ISO draft appendices on methodology	October 11
CPUC workshop: ISO 33% RPS study methodological issues/PGE methodology	October 22

Status of ISO Methodology and Simulations

- ISO continues to get feedback through the LTPP proceeding and other channels on methodology and results in the 20% RPS study and the ongoing 33% RPS analysis
- Step 1 methodology under review for assumptions about solar forecast error
- Step 2 methodology reflects modified assumptions discussed in prior workshop (and reviewed in these slides)
- Step 2 simulation results now available for review
- Opportunities for further refinement of both Step 1 and Step 2 methodology prior to next batch of CPUC scenario assumptions

This presentation builds on prior ISO presentations at CPUC LTPP workshops

- These slides reference:
  - ISO August 24-25, 2010 presentation
  - ISO October 22, 2010 presentation

- Prior ISO slides available at
  - http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm

SECTION 2: REFINEMENTS AND VALIDATION OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Core components of Step 1 model

- *Variability*: Methods to establish 1-minute data reflecting variability for load, wind and each solar technology type
- *Uncertainty*: Statistical properties of the forecast error for load, wind and each solar technology type
- *Interaction of forecast errors and variability*: Step 1 model uses random draws of forecast error (or persistence) by minute for each variable component to estimate load-following and regulation
- Possible extensions:
  - Alternative methods to determine variability of resources
  - different forecast errors by location; more analysis of spatial and temporal correlation between forecast errors; other considerations

Additional information on Step 1 inputs and analysis of data is available

- Statistical Analysis of 1 Minute Solar Profiles (created by Nexant) http://www.caiso.com/284c/284cc67251480.pdf
- 33% RPS Study Step 1 Input Profile Data http://www.caiso.com/23bb/23bbc01d7bd0.html
- Profiles and Locations for 1-minute data http://www.caiso.com/284c/284cc67251480.pdf
- Profiles and Locations for Hourly data http://www.caiso.com/2845/2845f08c5d0.pdf
- Validation of results: Comparison of Calculated Regulation/Load-Following Quantities with Actual Quantities - Summer 2010 http://www.caiso.com/284c/284cc71f57cd0.pdf

Development of solar forecast errors

- In 2009-10, ISO worked with Pacific Northwest National Lab (PNNL) to evaluate data on solar forecast errors by technology type and methods for including them in the statistical model (Step 1)
- Objective was to obtain a reasonable but also timely method given lack of actual forecast data and known modeling techniques
- ISO method and assumptions have been under review and possible changes/sensitivities are under discussion

Alternative assumptions about how statistical properties of solar forecast error are derived

- *Current approach*: ex ante assumption about standard deviation of errors associated with Clearness Index (CI) by hour (based on available data reviewed by PNNL)
  - Historical solar forecast error data
  - “Improved” errors
- *Alternative approach*: Determine errors by the persistence of the CI in period *t*-2
  - But need method to address first and last hour of solar production
- Results on next slide
  - CI persistence method for Hours 12-16 similar in outcome to “improved” errors

Comparison of solar forecast error with persistence

Calibration of Solar Profiles – Using T-2 Hour Persistence Forecast Method

Method based on T-2

CI (t-2) Forecast Error % By Clearness Index						
Profile	**Total MW**	**Case**	**0<=CI<0.2**	**0.2<=CI<0.5**	**0.5<=CI<0.8**	**0.8<=CI<=1**
Solar Thermal	5,968	T-2 All Hour	8.00%	14.90%	19.40%	18.90%
		T-2 Hr12-16	9.20%	13.20%	12.50%	6.00%
PV	3,170	T-2 All Hour	4.60%	9.00%	9.90%	6.70%
		T-2 Hr12-16	5.30%	10.10%	7.90%	3.90%
Out State Solar Thermal	534	T-2 All Hour	23.20%	21.60%	21.00%	16.90%
		T-2 Hr12-16	23.10%	23.50%	18.40%	11.50%
Distribute PV	2,262	T-2 All Hour	8.70%	7.10%	10.50%	10.60%
		T-2 Hr12-16	0.00%	3.90%	4.00%	2.10%
Total Solar	12,334	T-2 All Hour	5.20%	8.70%	12.00%	10.50%
		T-2 Hr12-16	4.80%	7.00%	7.10%	3.30%
Weighted Avg		T-2 All Hour	7.91%	12.15%	15.26%	14.00%
		T-2 Hr12-16	7.04%	11.07%	9.93%	4.95%

Current study assumptions

33% Study						
Each and All Profiles		Improved Error	5.00%	10.00%	7.50%	5.00%
Each and All Profiles		All Error	5.00%	20.00%	15.00%	5.00%
Each and All Profiles		Zero	0%	0%	0%	0%

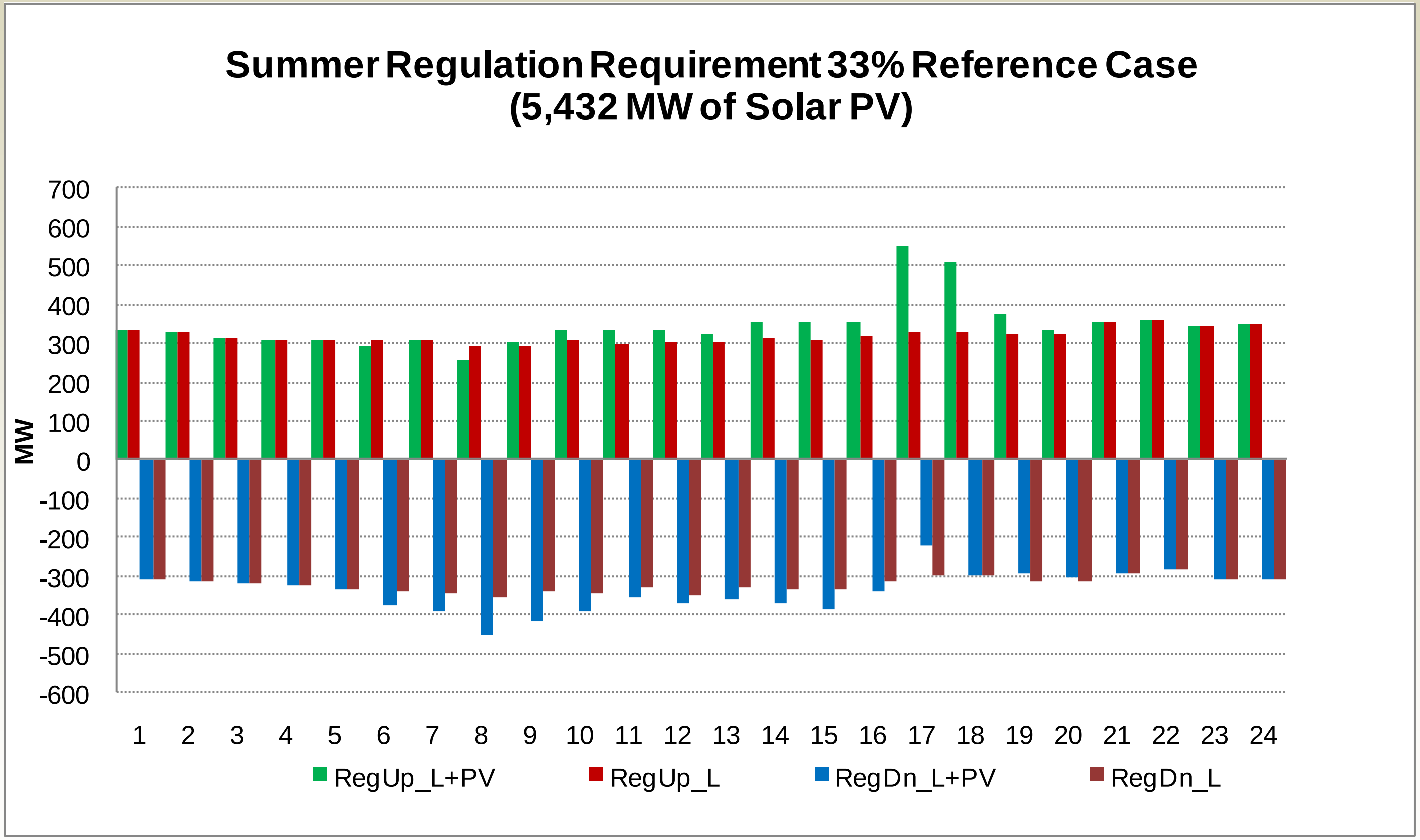
Analysis of solar production variability

- ISO modeling uses 1-minute data, both actual and synthesized, on solar production
  - Details of initial methodology described in draft technical appendix
- Current method captures impact of geographical diversity on variability of solar production
- Uses detailed spatial model with cloud speed assumptions and random draws from Clearness Index to reflect geographical diversity
- Alternative methods could also be considered and will be discussed further in the afternoon panel

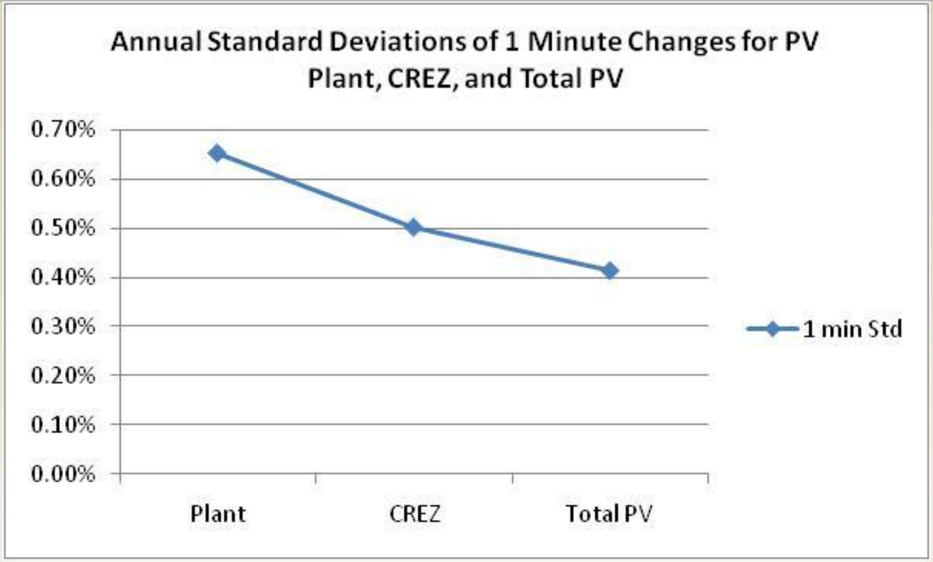
ISO modeling of PV Variability - Initial Results

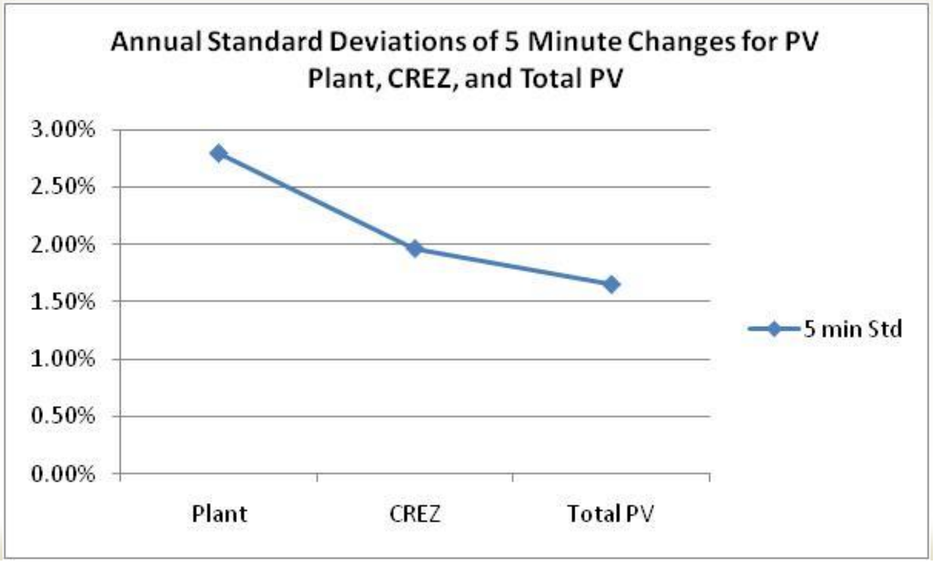
- Following slides examine
  - Variability of PV in the 33% Reference Case and estimate of its impact upon Regulation requirements
  - Variability statistics for PV in the 33% Reference Case for the fleet, for a single CREZ and for a single plant (Statistical data previously posted by the CAISO) for 1 and 5 minutes
  - Variability by hour for a non-tracking and tracking PV facility under clear sky conditions (no clouds) that demonstrates the variability pattern without clouds
- Additional work needed to understand components of variability due to sun’s movement and due to clouds and their impact upon regulation requirements

Impact of Solar PV on Regulation Requirement for all 24 Hours for Summer Season



Reduction in 1 Minute and 5 Minute Variability for PV with Increased Geographic Diversity

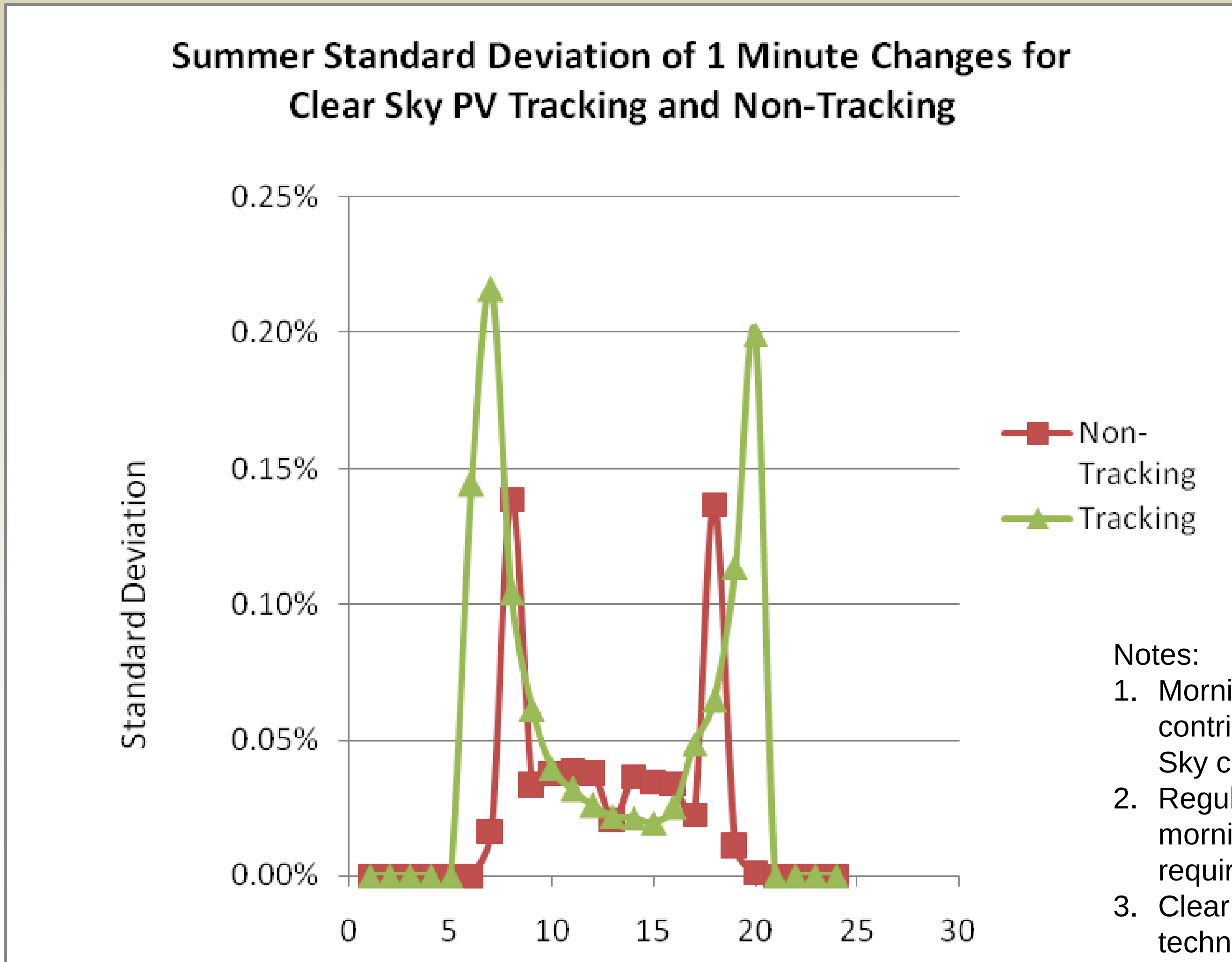




Notes:

1. Total PV is for entire PV portfolio of 5432 MWs
2. CREZ is for Carizzo North
3. Plant is 300 MW

Hourly Variability of 1 Minute Data for PV under Clear Sky Conditions



Notes:

1. Morning and evening ramps are major contributors to variability under Clear Sky conditions
2. Regulation requirements have same morning and evening peaks in requirements
3. Clear Sky variability is a function of PV technology with tracking PV having higher variability due to steeper ramps

SECTION 3:
PRODUCTION SIMULATION RESULTS
FOR CORE REFERENCE CASES (STEP 2)

Initial comments on method and results

- The focus of the presentation is on method rather than on initial results
    - Full analysis with sensitivities will be conducted on updated CPUC scenarios for 2020
- Some results are a function of assumptions that will be subjected to further sensitivity analysis
    - E.g., what range of operational requirements to model and how to interpret the implications
- Some results are a function of *ex post* processing of model outputs; alternative methods will yield different results within a range
    - E.g, allocation of import production costs to California load

Key common assumptions for production simulation cases

- WECC-wide model
- CPUC 2009-vintage 2020 scenarios (renewable portfolios, load forecasts, planned retirements/additions)
- Conventional dispatchable generation modeled with generic physical operating parameters
  - Inventory of operational flexibility capability – load following, regulating ranges – reviewed in Section 4
- Import constraints enforced
- Path 26 and SCIT constraints enforced
- Out of state renewables and dedicated imports dispatched as part of the Balancing Authority where they are located

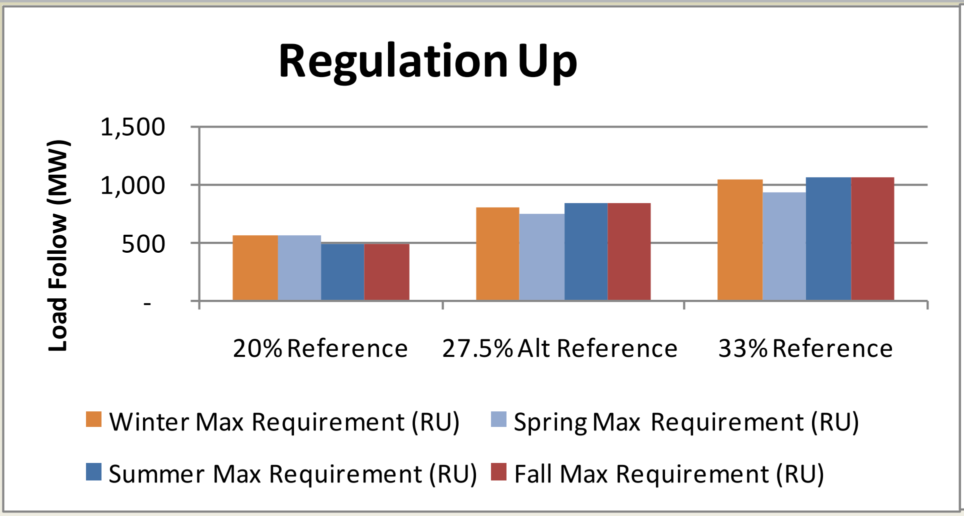
Renewable portfolios for 2020: *incremental* capacity (MW) for CPUC 2009-vintage scenarios

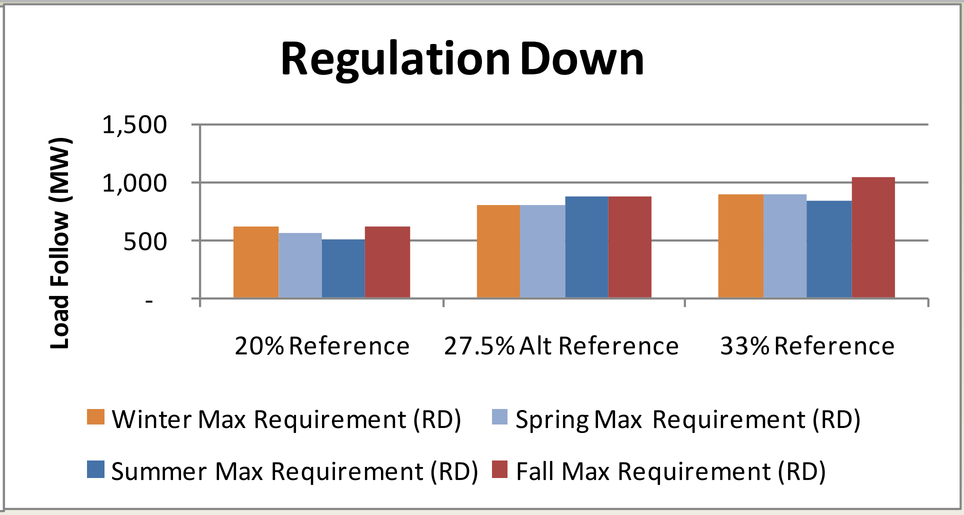
	Biogas	Biomass	Geo-thermal	Small Hydro	Solar Thermal	Solar PV	Wind
20% Reference	30	324	1,052	37	107	333	5,024
33% Reference	279	429	1,497	40	6,513	3,165	8,338
Out-of-State (OOS)	279	339	2,532	49	1,753 (534 Outside CA)	890	10,870 (6,290 Outside CA)
High Distributed Generation	234	328	1,298	37	1,095	15,959 (15,098 DG)	5,067
27.5%	30	328	1,298	40	4,868	2,864	5,977
Low Load	30	328	1,299	40	4,907	2,867	7,091

Production simulation results in this section reflect certain assumptions

- Intra-hourly operational needs from Step 1 assume seasonal maximum requirements for each hour
  - Regulation, load-following
- Additional resources are needed to resolve operational constraints (ramp, ancillary services)
- Renewable resources located outside California to serve California RPS will create costs that will be transferred to California load-serving entities

Initial assumptions about hourly Regulation capacity requirements, by scenario (input from Step 1 to Step 2)

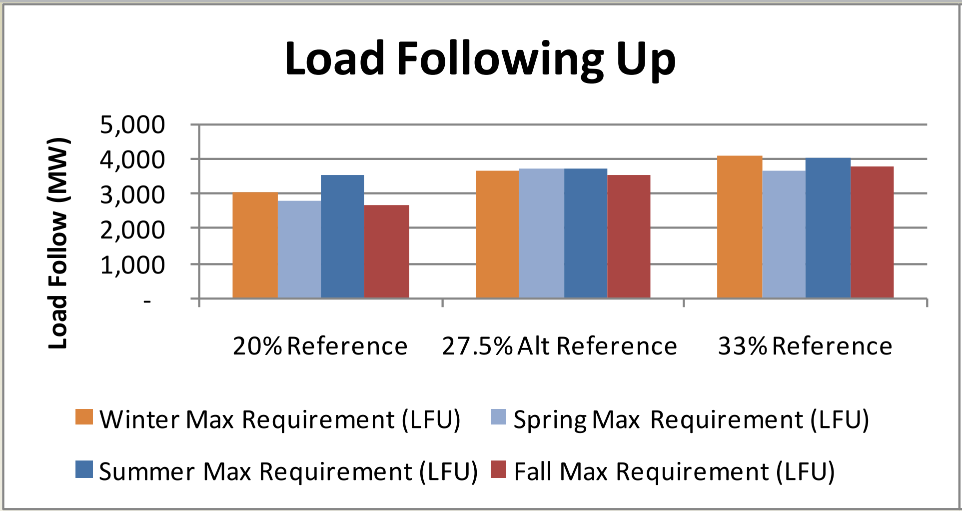


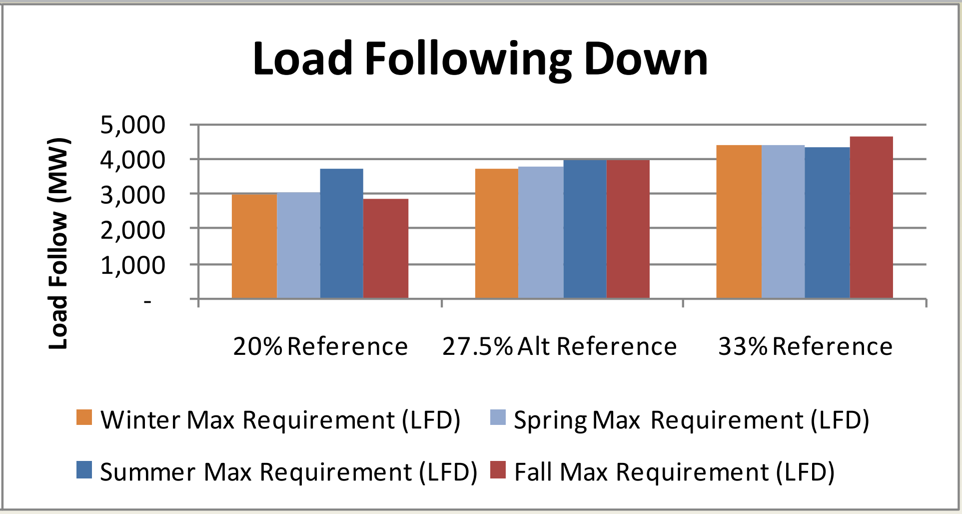


Note:

- For purposes of comparison, the figures show the single highest hourly requirement from Step 1 for each season (assuming the 95th percentile is the maximum value)
- The actual cases use the maximum seasonal requirement by hour
- Discussion of sensitivity assumptions in Section 3

Initial assumptions about hourly load-following capacity requirements, by scenario (input from Step 1 to Step 2)





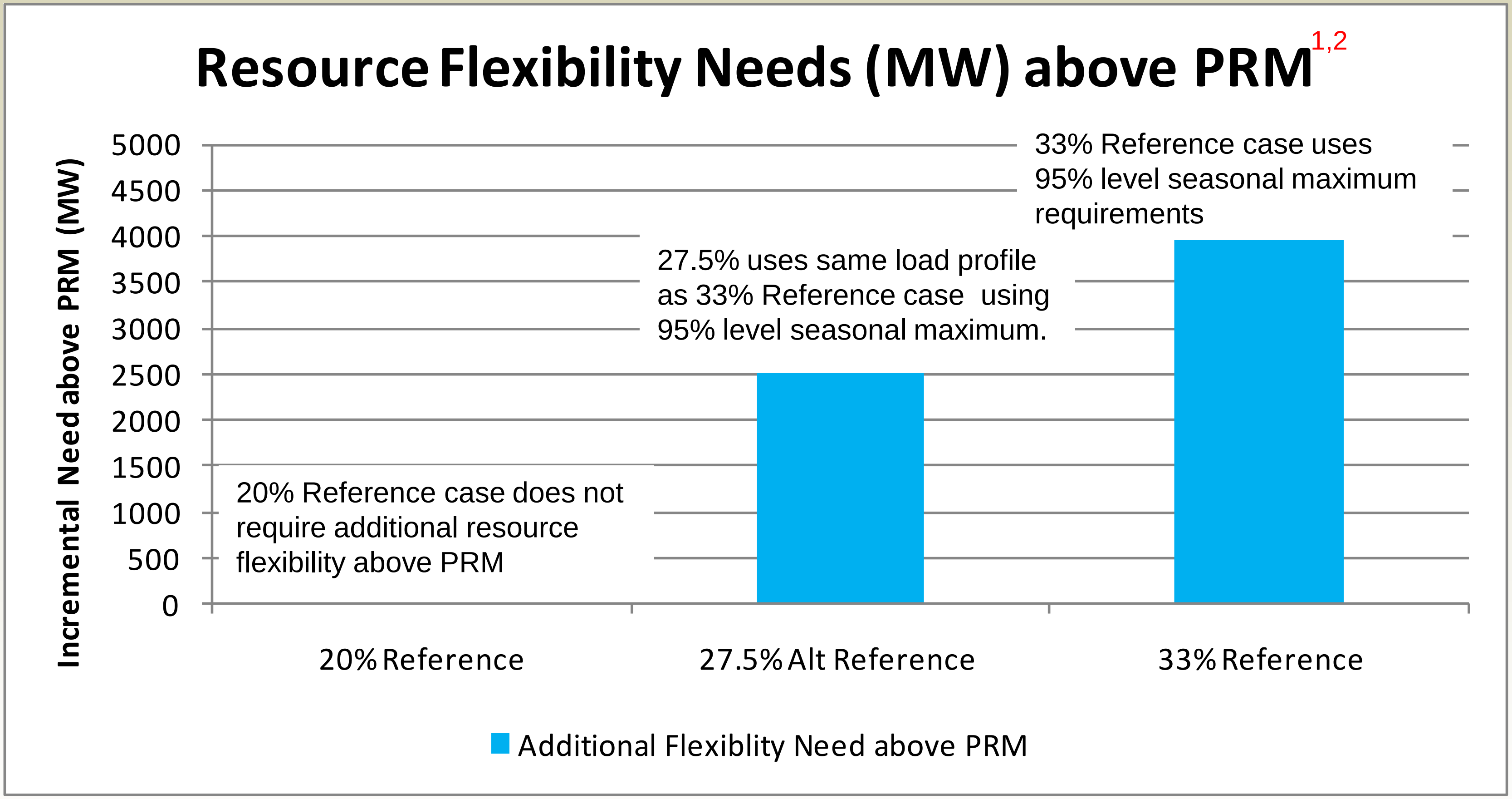
Note:

- For purposes of comparison, the figures show the single highest hourly requirement from Step 1 for each season (assuming the 95th percentile is the maximum value)
- The actual cases use the maximum seasonal requirement by hour
- Discussion of sensitivity assumptions in Section 3

The analysis adds resources above the Planning Reserve Margin (PRM) to resolve operational violations

- Methodology described in ISO August 24-25 slides; assumed fleet flexibility capability described in ISO October 22 slides and Section 4 of this presentation
- Next slide shows additional conventional resources needed to resolve operational violations, by scenario
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Additional capacity (MW) of flexible resources needed above Planning Reserve Margin (PRM)



1. Note that modeling assumptions include use of CPUC 2009-vintage scenarios and seasonal maximum requirements for load-following and regulation (see slides 19, 21 and prior ISO presentations); sensitivity results are shown on slide 69
2. All reference scenario flexibility was satisfied by adding conventional (LMS100 CTs & LM6000) as a proxy for flexible capacity but may be satisfied with resources/mechanisms that provide similar flexibility characteristics..

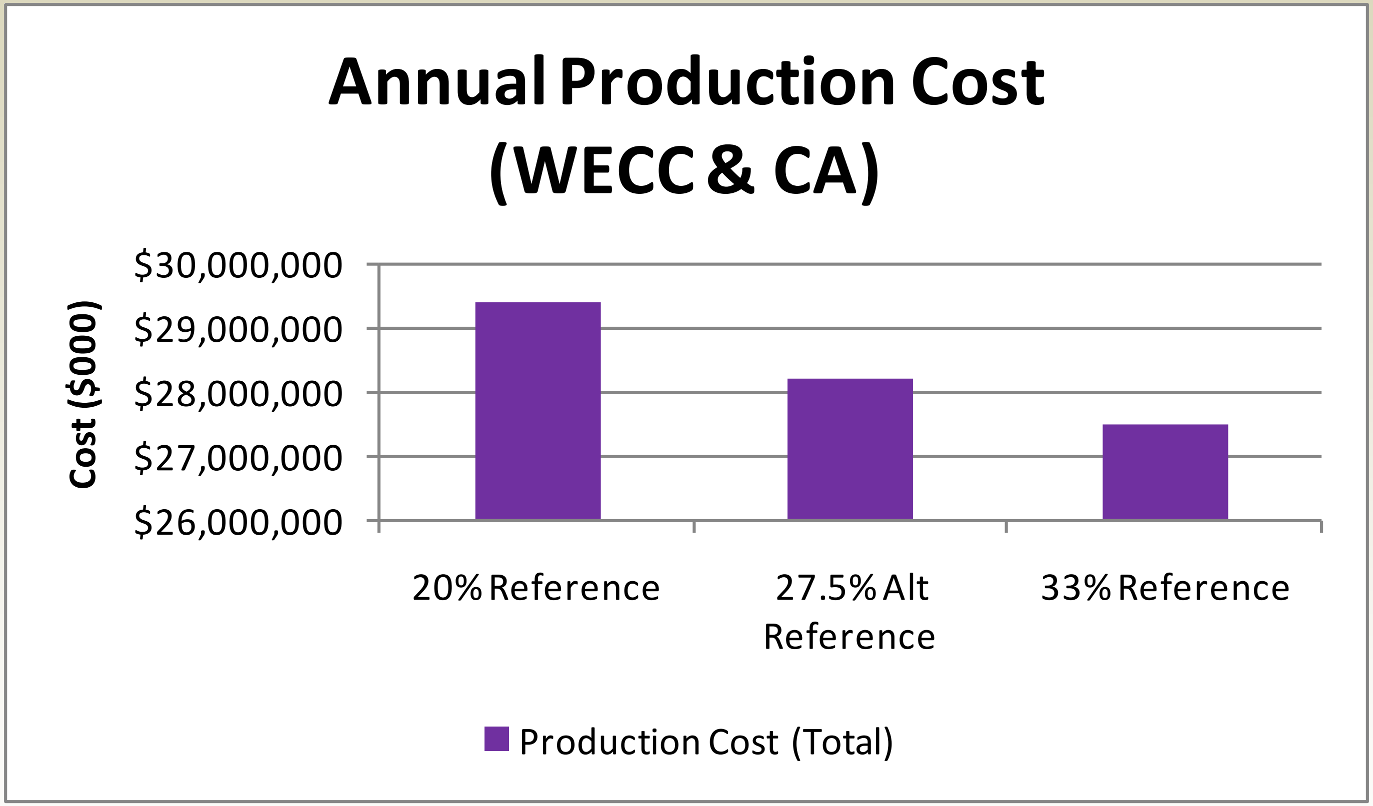
Discussion of results on additional resources

- The dispatchable resources available under the *current* PRM methodology may not be sufficiently flexible by 2020 to integrate renewable resources, even with optimal unit commitment and dispatch (as assumed in production simulation)
- Trend in additional capacity needed to resolve operational violations is consistent with expectations (i.e., more violations with more variable resources modeled)
  - Both “All Gas” and 20% RPS cases were run and no additional flexibility capability was required (i.e., no operational violations)
- Results are sensitive to alternative assumptions about integration requirements and mix of generation types; for comparison, see Section 3

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs and fuel burn are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports

Annual production costs ($) for California and rest of WECC by scenario



Components for calculating California production costs

CA GENERATION COSTS

+

(CA IMPORTS — CA EXPORTS)

CA IMPORTS

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - i.e. Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

CA EXPORTS

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

Calculating total California production costs

+ CA Generation Costs

- Costs to operate CA units (fuel, VOM, start costs)

+ Cost of Imported Power (into CA)

- Dedicated Import Costs
- Undesignated (or non-dedicated) Import Costs
- Out of State renewables (zero production cost)

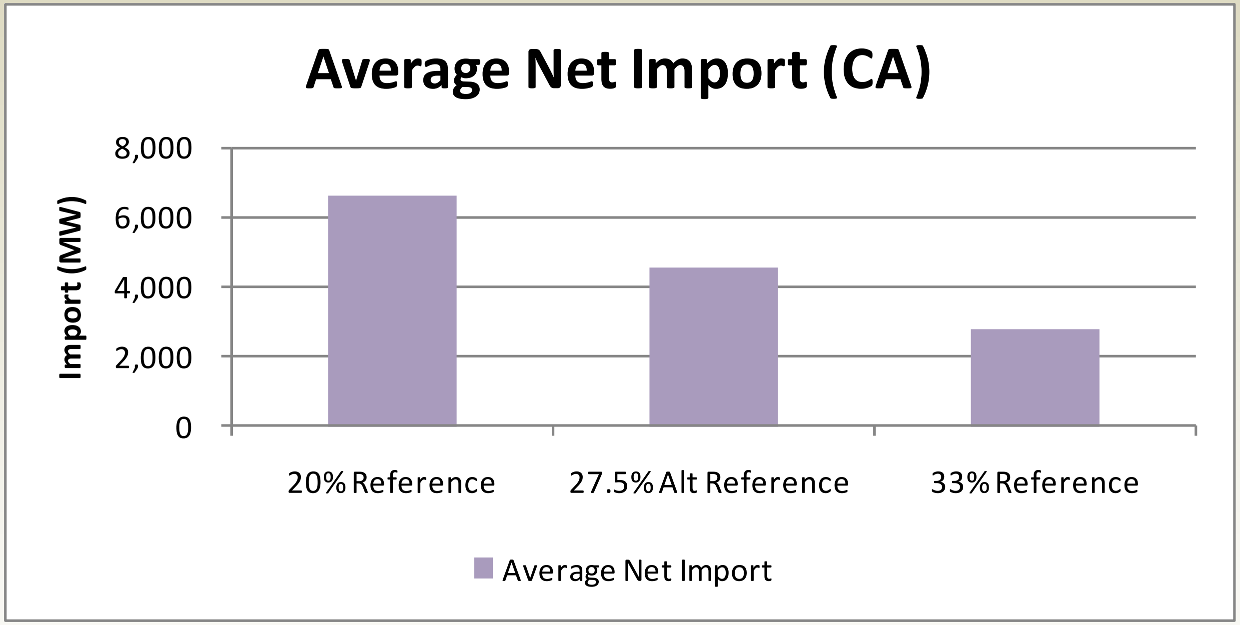
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

= Total Production Cost of meeting CA load

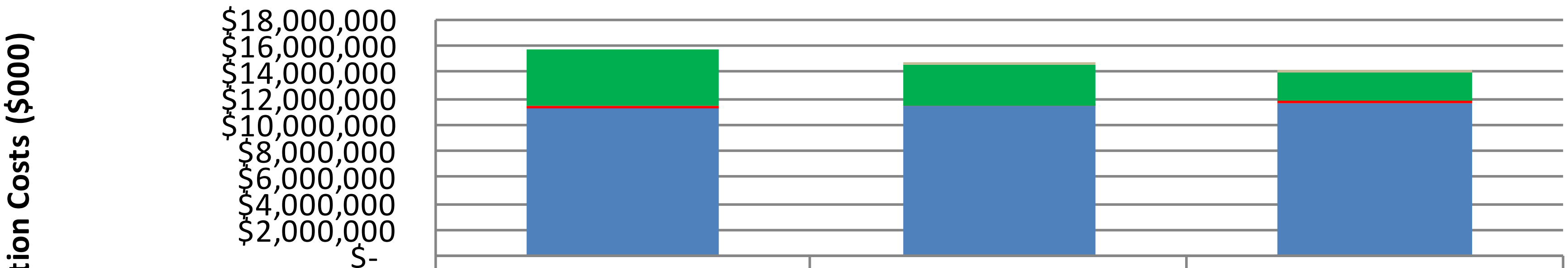
Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

Net Imports decline at higher RPS (based on assumptions about in-state renewable production), results by scenario



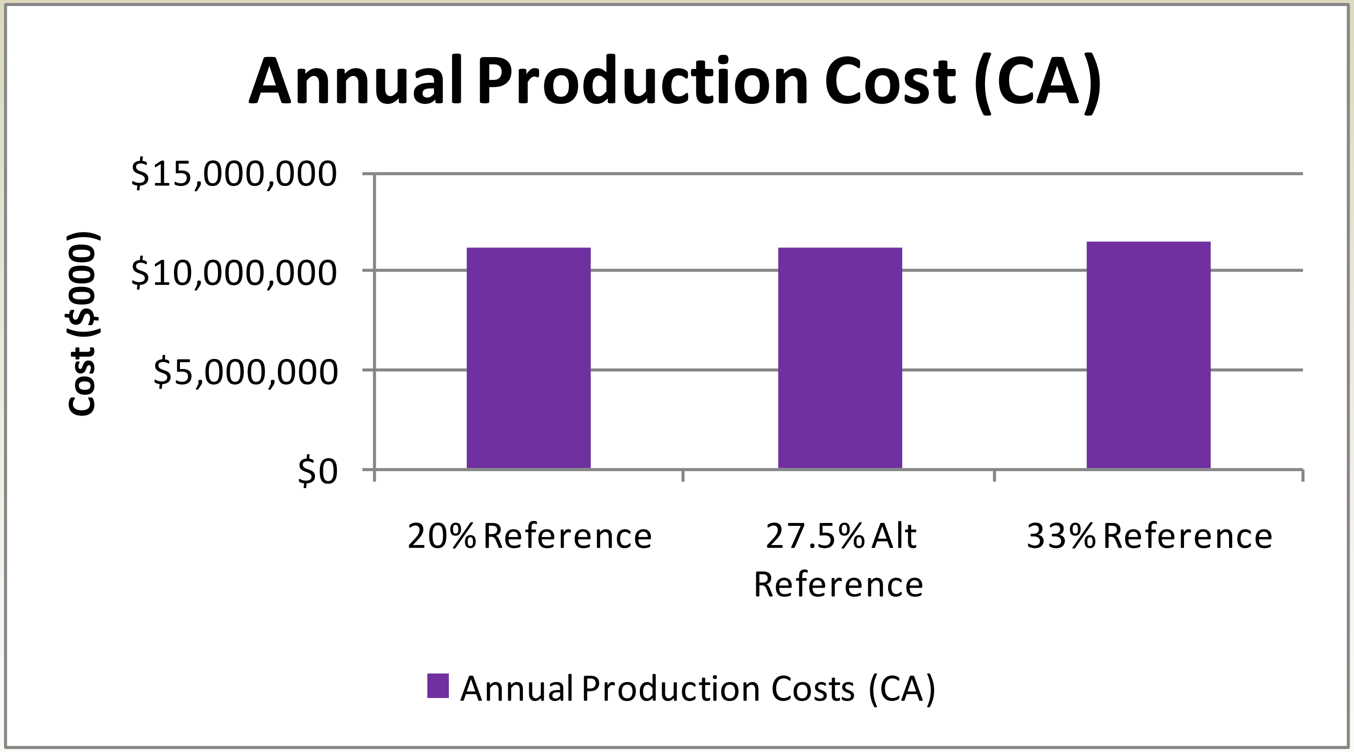
Total annual production costs ($) associated with California load (accounting for import/exports), by scenario

Production Costs to Meet CA Load Accounting for Imports / Exports

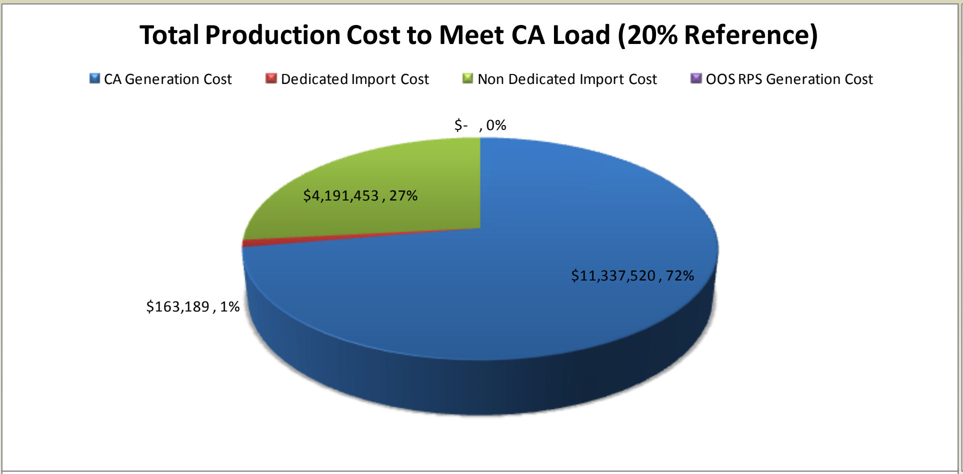


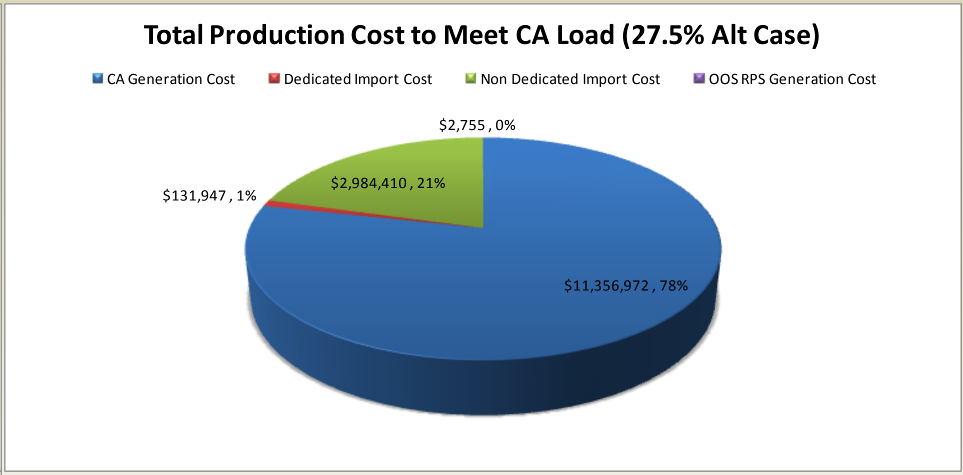
	20% Reference	27.5% Alt Reference	33% Reference
OOS Non-Generation Costs	$-	$2,755	$2,731
Non-Dedicated	$4,191,453	$2,984,410	$2,124,524
Dedicated	$163,189	$131,947	$101,070
CA Generation Prod Costs	$11,337,520	$11,356,972	$11,709,762

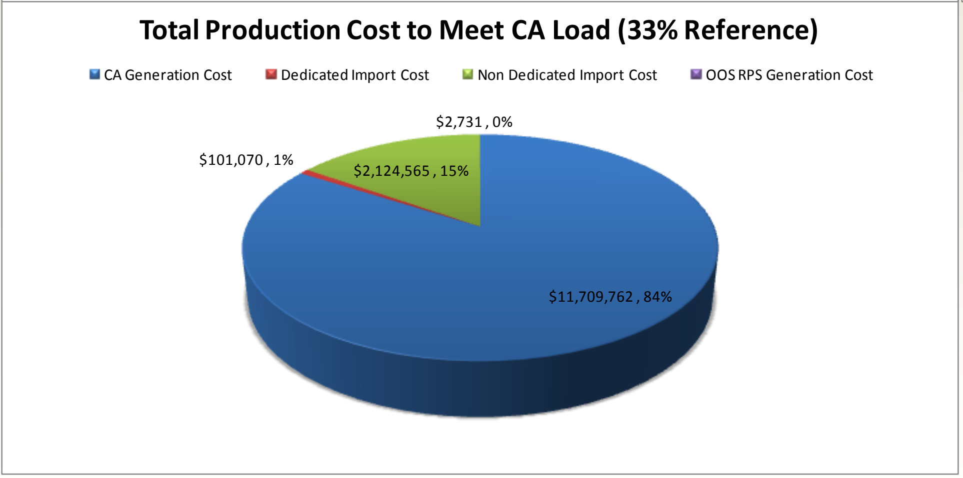
California annual production costs ($) by scenario



Comparison of Production Cost Results – To Meet CA Load (Accounting for Import/Exports)



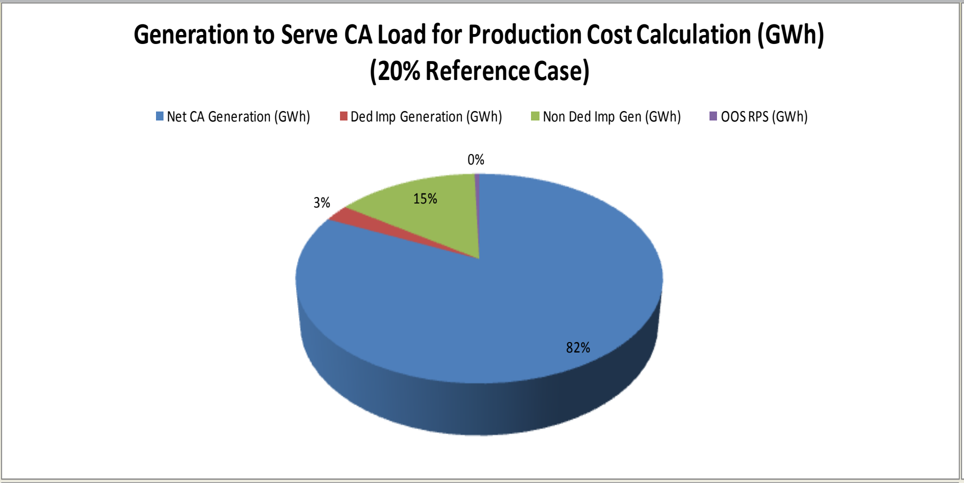


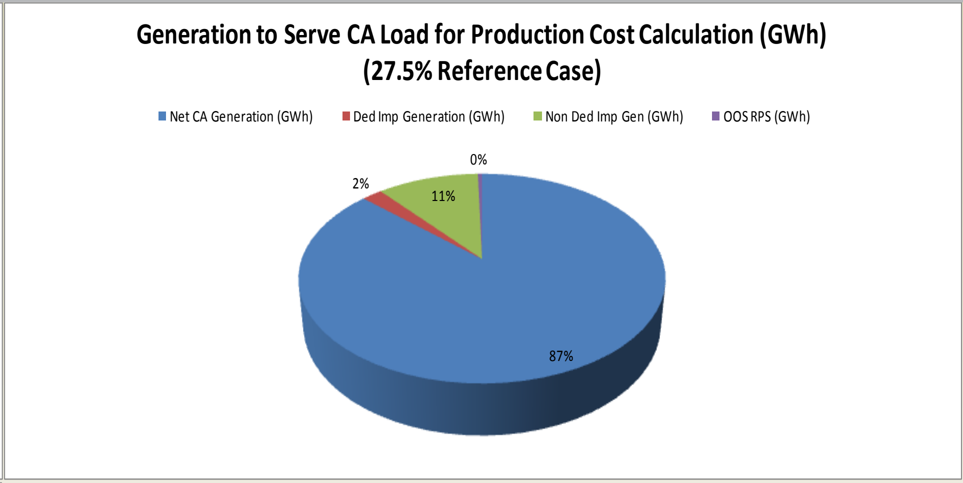


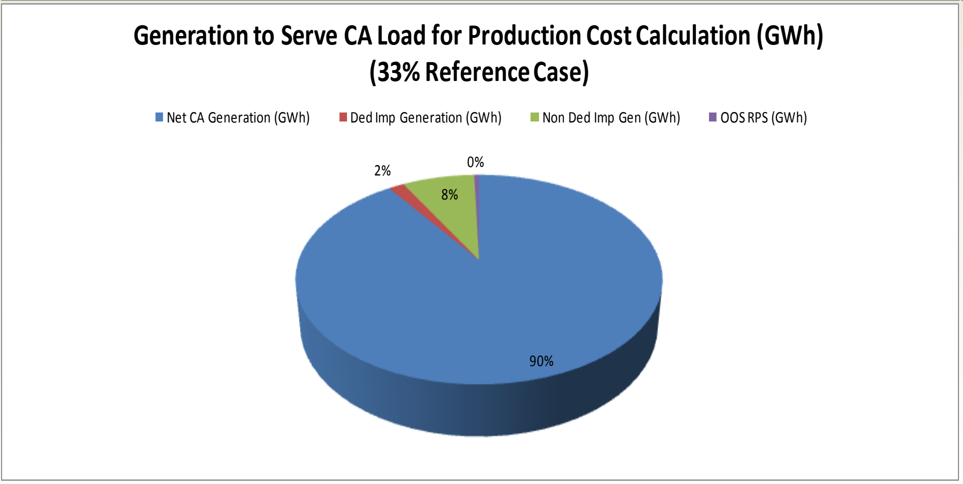
Notes:

1. Imports are attributed hourly to energy from external resources in the following order up to assigned tie import flow:
   1. OOS Renewable
   2. Dedicated resource imports
   3. Non-Dedicated resource imports
2. Out-of-State (OOS) Renewable cost zero
3. Integration cost for non-dynamic portion of OOS renewables are not accounted for
   1. 70% of OOS renewables are assumed to be firmed/shaped externally (remainder through dynamic transfer to ISO)
4. Value of OOS renewable energy not imported into state is not accounted for

Comparison of Production (GWh) Results – To Meet CA Load (Accounting for Import/Exports)







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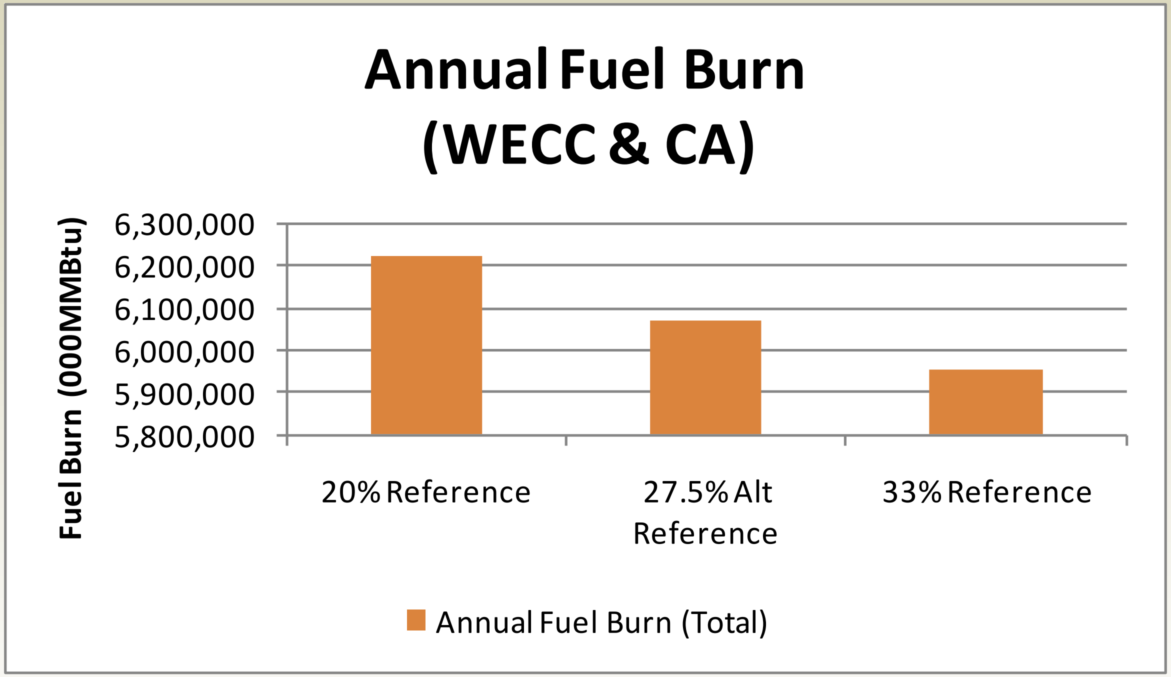
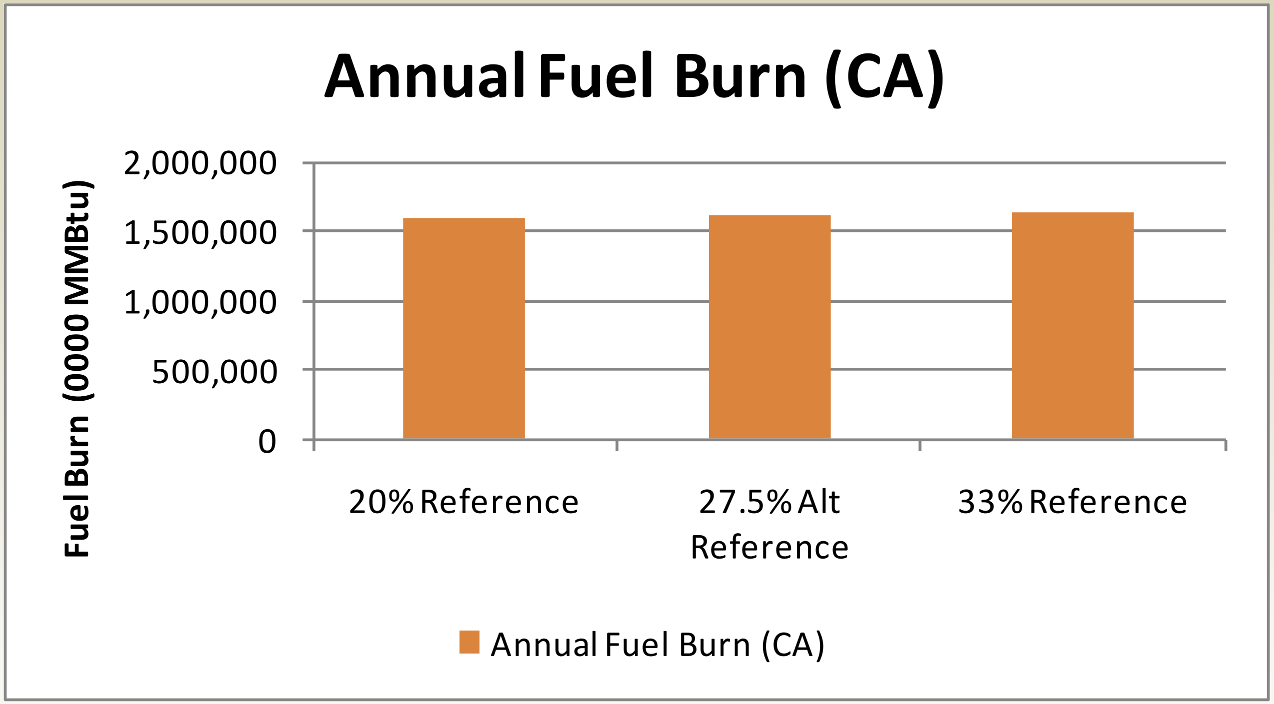
3. Integration cost for non-dynamic portion of OOS renewables are not accounted for
   1. 70% of OOS renewables are assumed to be firmed/shaped externally (remainder through dynamic transfer to ISO)
4. Value of OOS renewable energy not imported into state is not accounted for

Total WECC (including CA) fuel burn (MMBTU), by scenario



MMBTU = million BTU for conventional/fossil resources

Total fuel burn (MMBTU) for in-state generation in California, by scenario



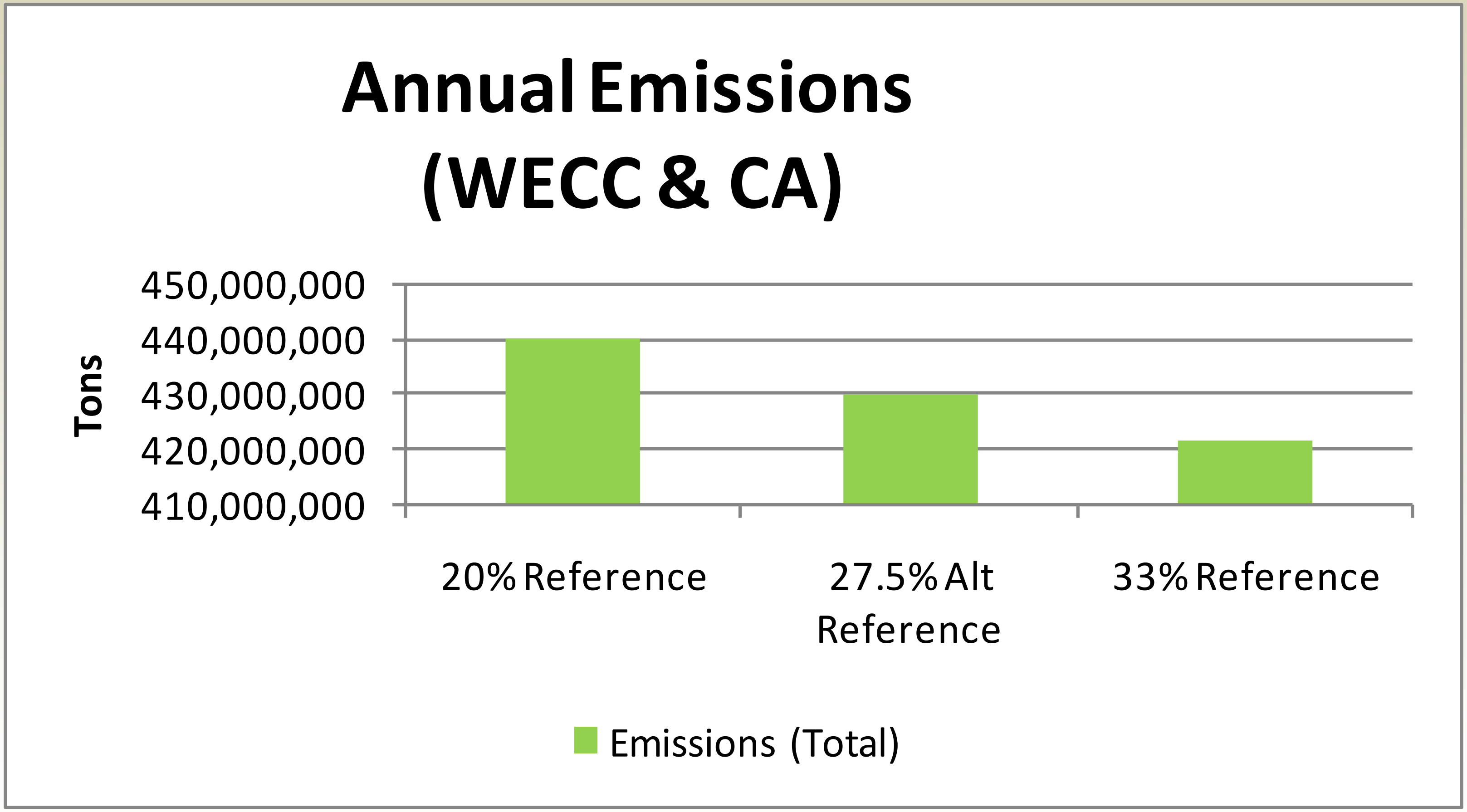
MMBTU = million BTU for conventional/fossil resources

GHG emissions calculations

- GHG emissions are calculated by heat rate (MMBTU/MWh) × fixed emissions factor (lbs/MMBTU)
- Plants with multiple-step heat rate curves will have different emissions/MWh depending on their output in each hour of the simulation (two actual plants in table below)

Supply curve:		Segment 1	Segment 2	Segment 3
Plant 1	MW	68	170	340
	Heat rate	11750	10100	9600
Plant 2	MW	263	394	525
	Heat rate	8000	7300	7000

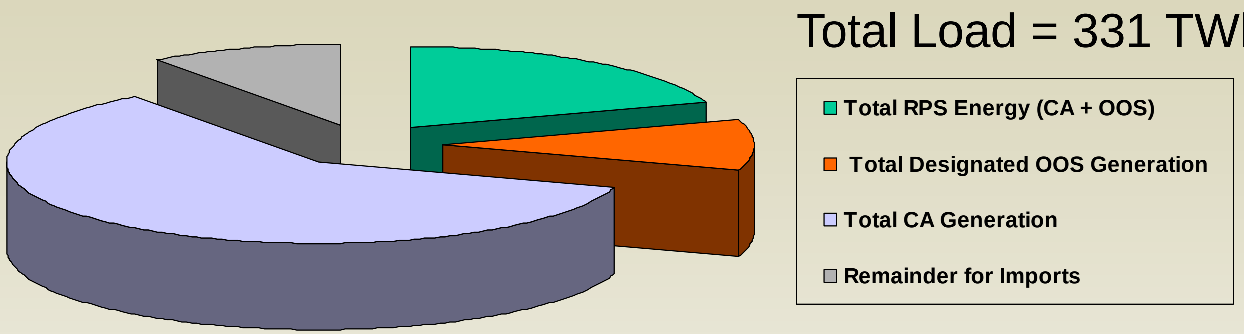
Annual WECC emissions by scenario



Calculation of GHG emissions associated with California

- Production simulation modeling output includes GHG emissions (tons/MMBTU) per generator to capture WECC-wide emissions reductions, but:
  - The model solves for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all OOS RPS energy dedicated to CA may “flow” into CA for every simulated hour as it could in actual operations (thus reducing GHG emissions in CA)
- To ensure that the emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

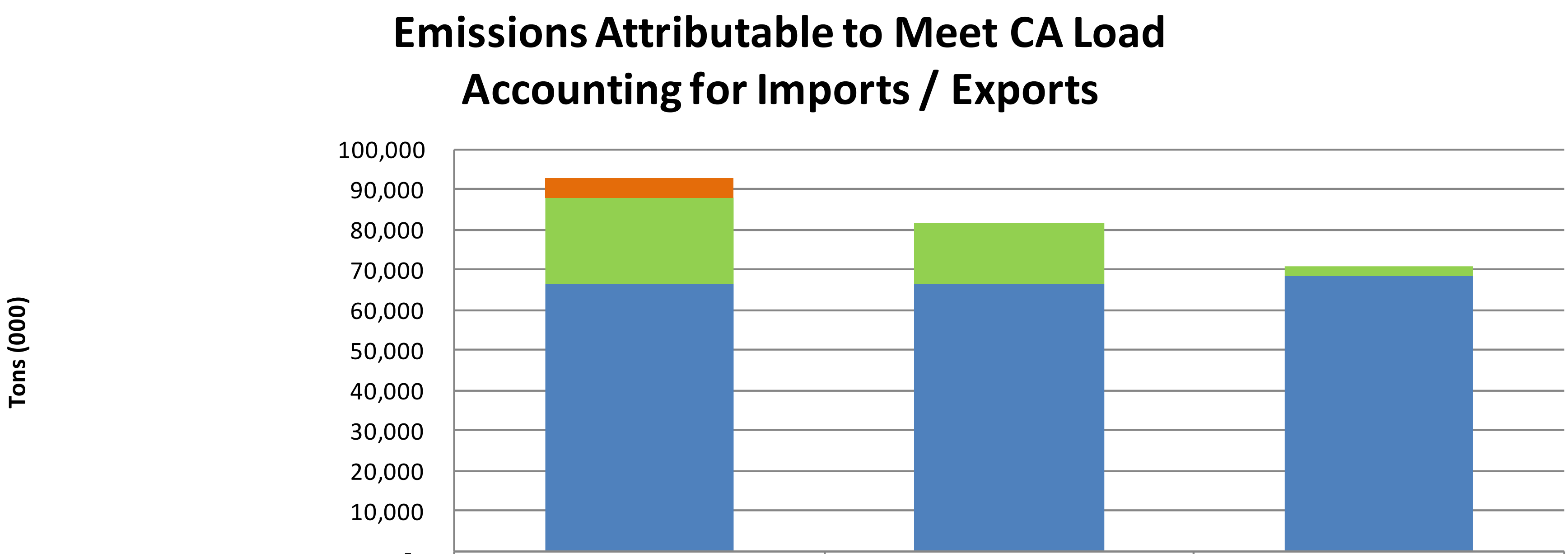
Calculation of GHG emissions associated with California load: emissions allocation methodology



- RPS energy will have a zero emissions rate for calculation of displacement of import emissions; assumes 100% of OOS RPS is assumed to meet California load
- Total CA generation emissions will come from production simulation modeling (by generation unit)
- Total dedicated OOS (non-renewable) generation emissions will come from production simulation modeling
- The non-dedicated (generic) import emissions are assigned at a rate of .44 metric tons/MWh.*

** This emissions rate is equivalent to a CCGT burning natural gas with a heat rate of 8,300, as provided by the CPUC*

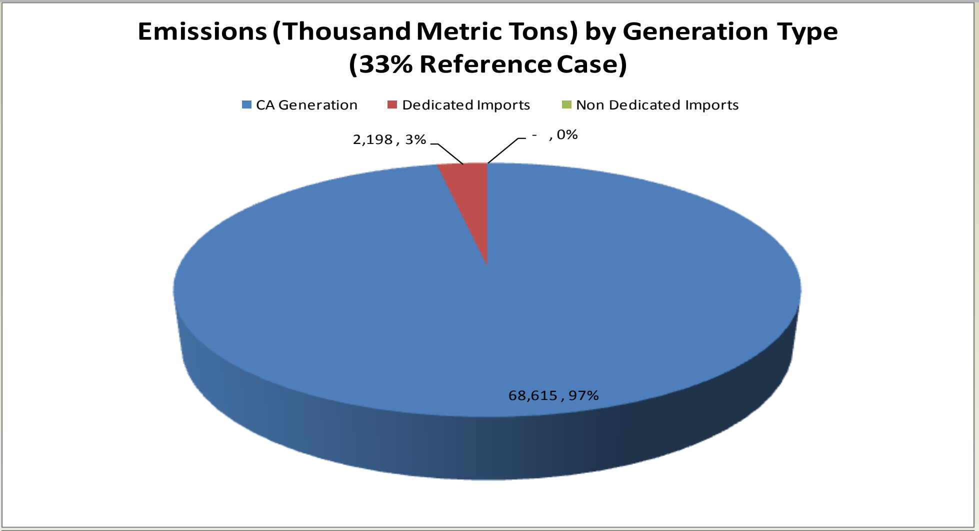
Emissions attributed to meet California load (accounting for Import/Exports[1]), by scenario and emissions source

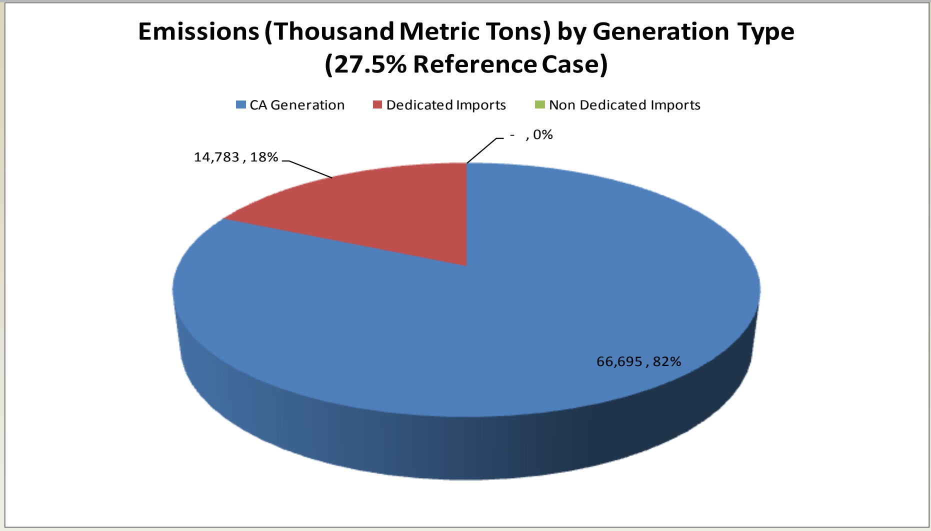


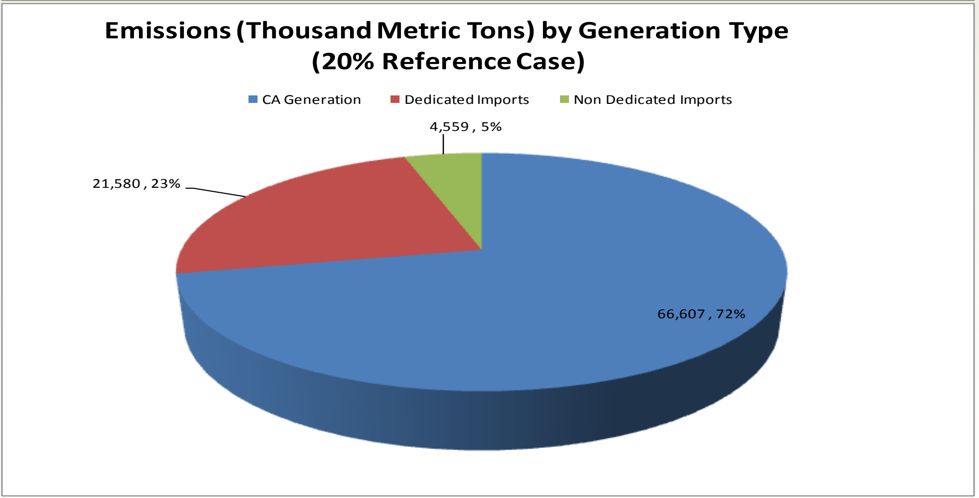
	20% Reference	27.5% Alt Reference	33% Reference
Emissions from Non-Dedicated Import	4,559	-	-
Emissions from Dedicatied Imports	21,580	14,783	2,198
CA Emissions	66,607	66,695	68,615

1. Attribution of emission for imports is performed based on the annual net import basis based on the .44 metric tons/MWh rate

Emissions to meet California load (accounting for Import/Exports), by scenario and emissions source







Notes:

1. Out-of-State (OOS) Renewable have zero emissions for import accounting
2. 100% of OOS RPS is assumed to meet California load

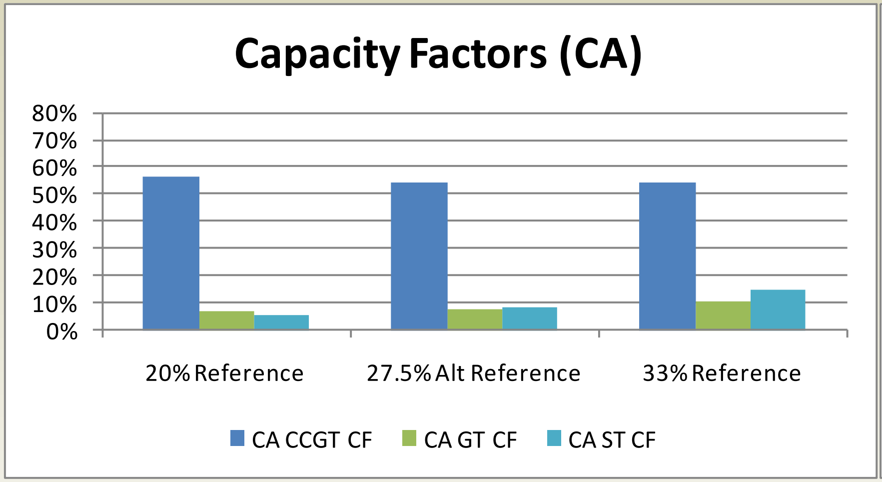
Discussion of emissions results

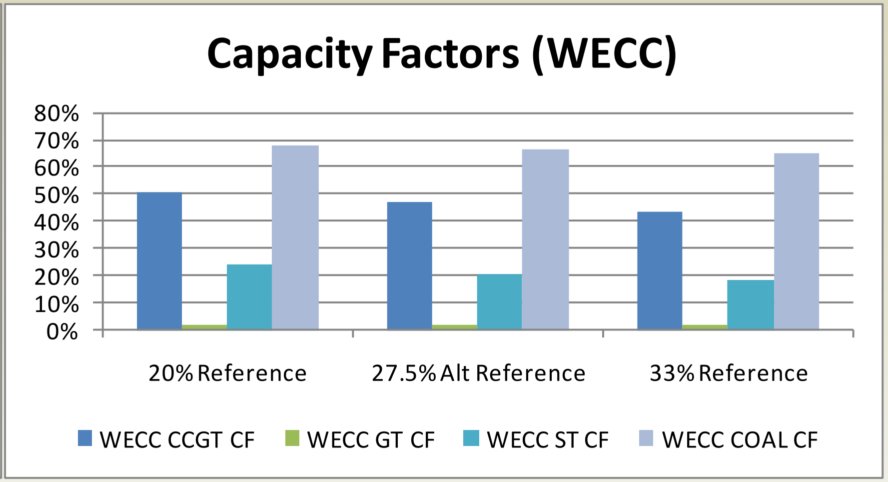
- Total emissions reduction assigned to California includes contribution of imports
- Emissions impact from California in-state generation is due in part to operational requirements associated with integration
  - Total emissions from California generators are lower in the sensitivity analysis on operational requirements discussed in Section 3
- Results are sensitive to method for allocating renewable energy imports to California load
  - Ex post method for assigning emissions reductions to California load may underestimate actual emissions reduction value; other approaches could be evaluated

Changes to fleet operations

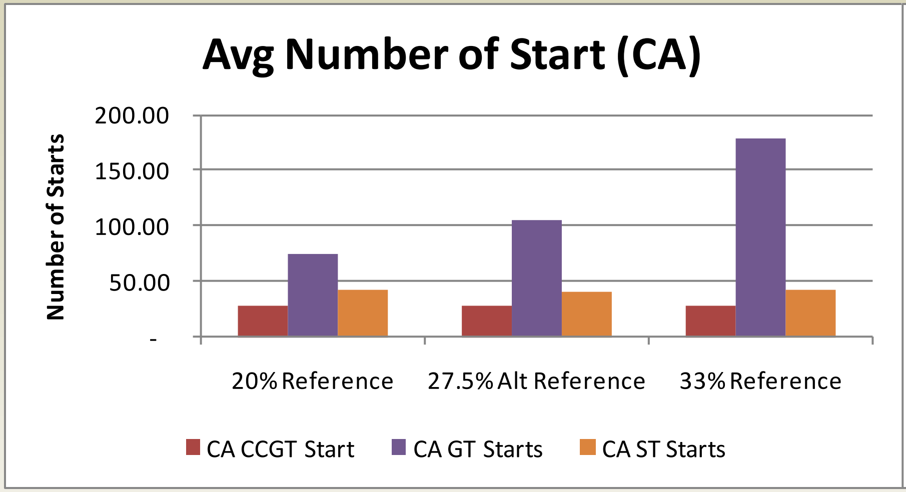
- Changes in capacity factors, number of starts by unit type and location
- California within-state results are influenced by integration requirements within state
- Linked to production costs and emissions, as shown in earlier slides

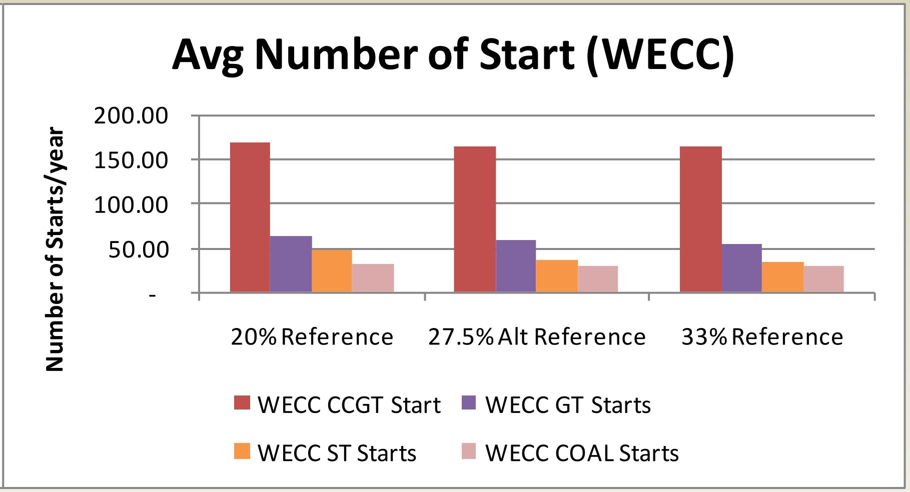
Changes to Capacity Factors, by scenario





Changes to number of Start-ups, by scenario





Comparison of CA and WECC (exclusive of CA) Results (2)

Comparison of Dispatchable Resources (CA versus WECC) (20% Reference Case)

Technology	CA		WECC (Excl CA)		Diff(CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	56.47%	28.47	50.77%	169.15	5.70%	-140.68
Coal	N/A	N/A	67.99%	31.65	N/A	N/A
GT	6.65%	75.35	2.18%	64.13	4.48%	11.21
ST	5.32%	41.94	23.94%	47.64	-18.62%	-5.70

Comparison of Dispatchable Resources (CA versus WECC) (27.5% Alternative Reference)

Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	54.32%	27.40	46.95%	164.75	7.38%	-137.35
Coal	N/A	N/A	66.56%	30.53	N/A	N/A
GT	7.87%	104.67	1.99%	59.84	5.88%	44.82
ST	8.39%	40.65	20.56%	37.89	-12.17%	2.75

Comparison of Dispatchable Resources (CA versus WECC) (33% Reference Case)

Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	54.11%	27.51	43.61%	165.17	10.51%	-137.66
Coal	N/A	N/A	64.81%	29.89	N/A	N/A
GT	10.79%	178.17	1.85%	55.67	8.94%	122.50
ST	14.55%	41.88	18.12%	35.43	-3.57%	6.45

SECTION 3: SENSITIVITY RESULTS FOR PRODUCTION SIMULATION (STEP 1/STEP 2)

Description of completed/in process sensitivities for 33% Reference Case

1. Alternative generation resource mixes to address flexibility needs
2. Hourly load-following capacity requirements (i.e., each hour of season) rather than seasonal maximum requirements for each of the 24 hours
3. Assumption of 90th percentile rather than 95th percentile values for Step 1 hourly load-following requirements
4. No load-following down capacity reservations (Not yet complete)
5. “Residual” vs. total load following (Not yet complete)

Sensitivity 1: Alternative resource technology mix

- Not previously discussed in ISO presentations
- Preliminary evaluation of how different thermal resource technology mixes could alter the ability to meet integration requirements
  - Begin to explore trade-offs between operational flexibility, cost and operational requirements
- No change to assumptions about operational requirements described in Section 2
- Assumptions on next slide refer to all new generation added to the model to meet PRM and additional operational requirements

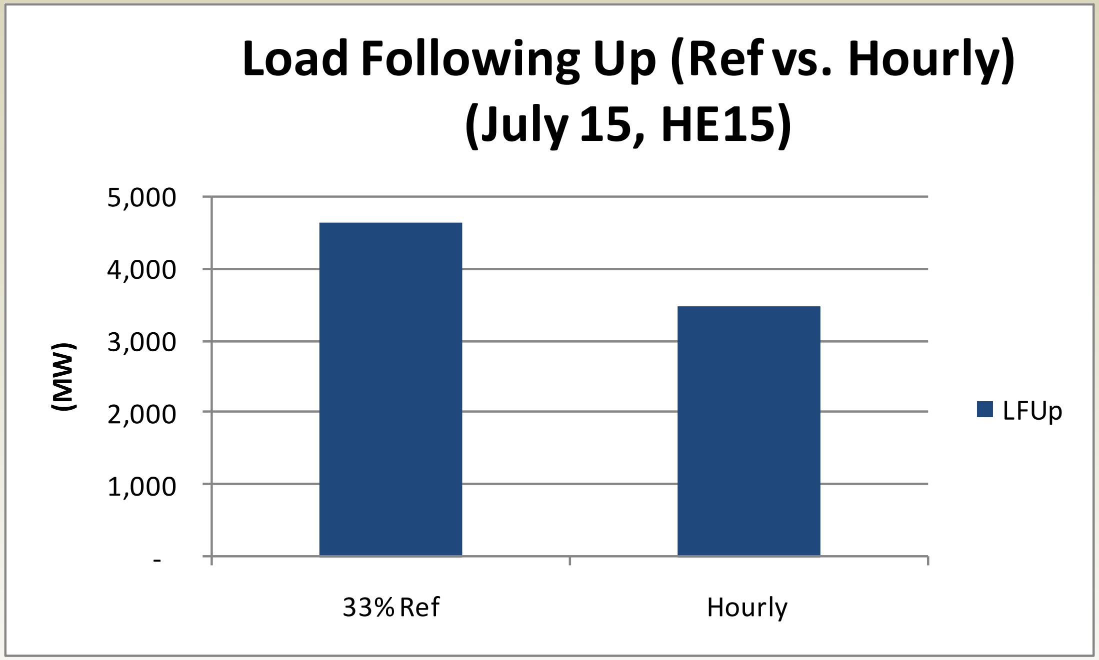
Sensitivity 1 (cont.): Alternative resource technology mix

- PG&E area 1000 MW of generic build-out from CCGT
- SCE area 1500 MW of generic build-out from CCGT
- Balance of generic build-out from LMS 100; no LMS 6000
- CCGT Characteristic
  - Pmin = 200 MW, Pmax = 500 MW
  - Ramp-Rate = 7.5 MW/min
  - Load following capacity = 150 MW (20 mins.), Regulation capacity = 75 MW (10 mins.)
- LMS 100 Characteristic
  - Pmin = 40 MW, Pmax = 100 MW
  - Ramp Rate = 12 MW/min
  - Load Following capacity = 60 MW (20 mins.), Regulation capacity = 37 MW (10 mins); both equivalent to max. operational range

Sensitivity 2: Substitution of hourly for seasonal Step 1 load-following requirements

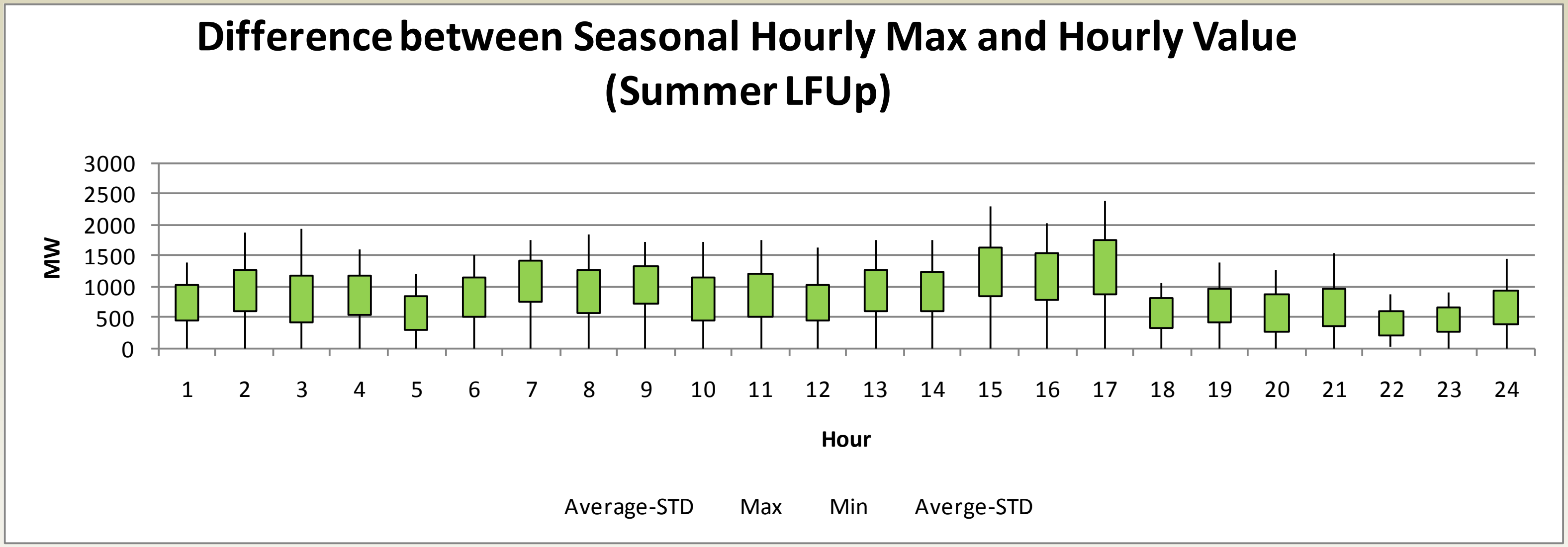
- Described in ISO October 22 presentation, slides 20-21
- Seasonal maximum requirements better capture possible “stress” conditions, but assume more load-following reserves than may actually be needed
- Sensitivity is used to better reflect likely load following capacity requirements on average, although it could understate maximum needs
  - Only one set of annual renewable production profiles is being used to generate operational requirements; other production profiles could generate other distributions of requirements
  - Could miss combinations of high load-following needs during high load hours

Sensitivity 2 (cont.): comparison of seasonal maximum and hourly value for one hour in the 33% RPS Reference Case (2009 vintage)



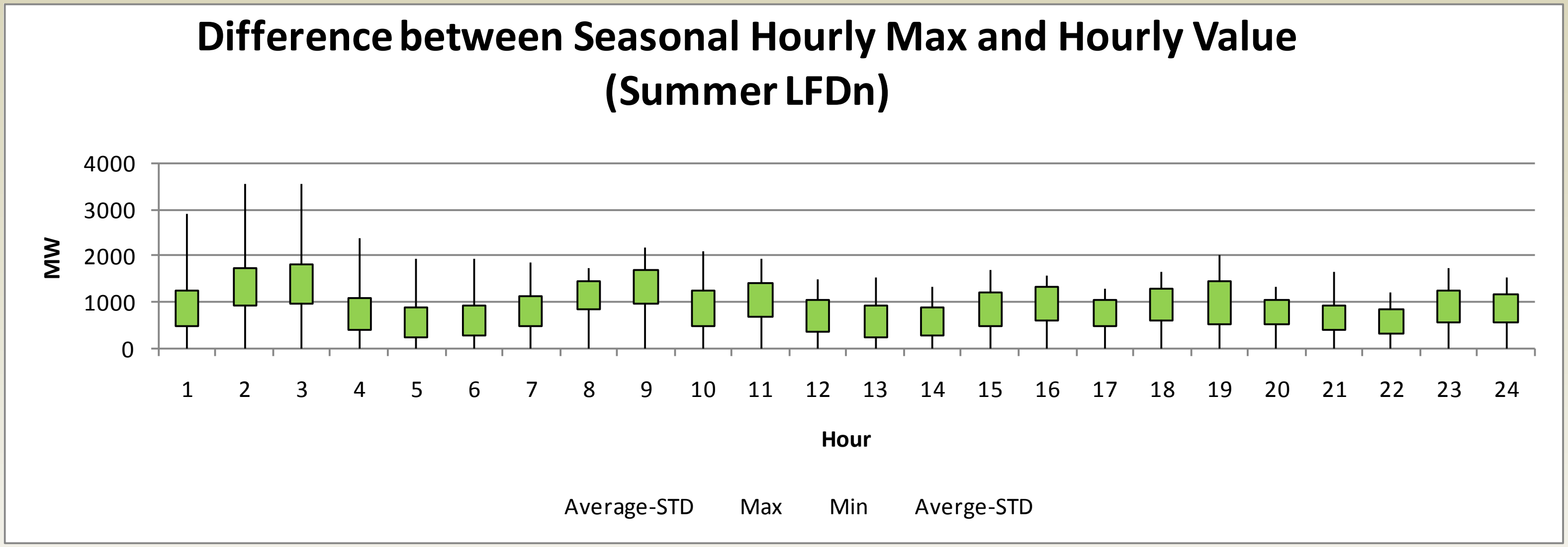
- For July 15 HE15, the model calculated 1147 MW less load-following up requirement than the seasonal maximum requirement (i.e., for summer HE15)

Sensitivity 2 (cont.): Difference between load-following up hourly and seasonal maximum requirements, Summer 33% RPS Reference Case (2009 vintage)



- Substitution of hourly for seasonal maximum load following up requirements results in approximately 700 MW-1000 MW difference on average

Sensitivity 2 (cont.): Difference between load-following down hourly and seasonal maximum requirements, Summer 33% RPS Reference Case (2009 vintage)

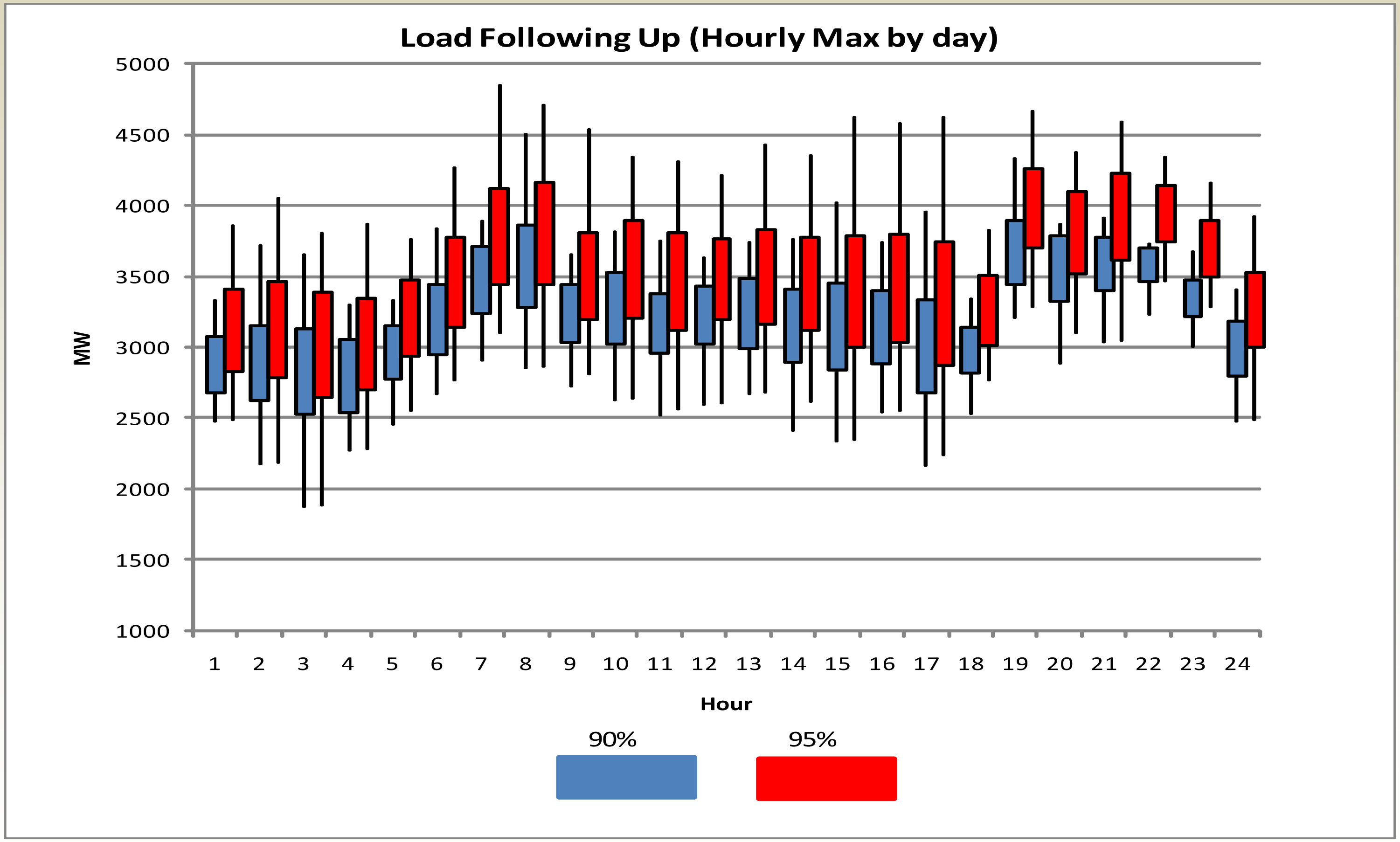


- Substitution of hourly for seasonal maximum load following down requirements results in approximately 700 MW-1000 MW difference on average

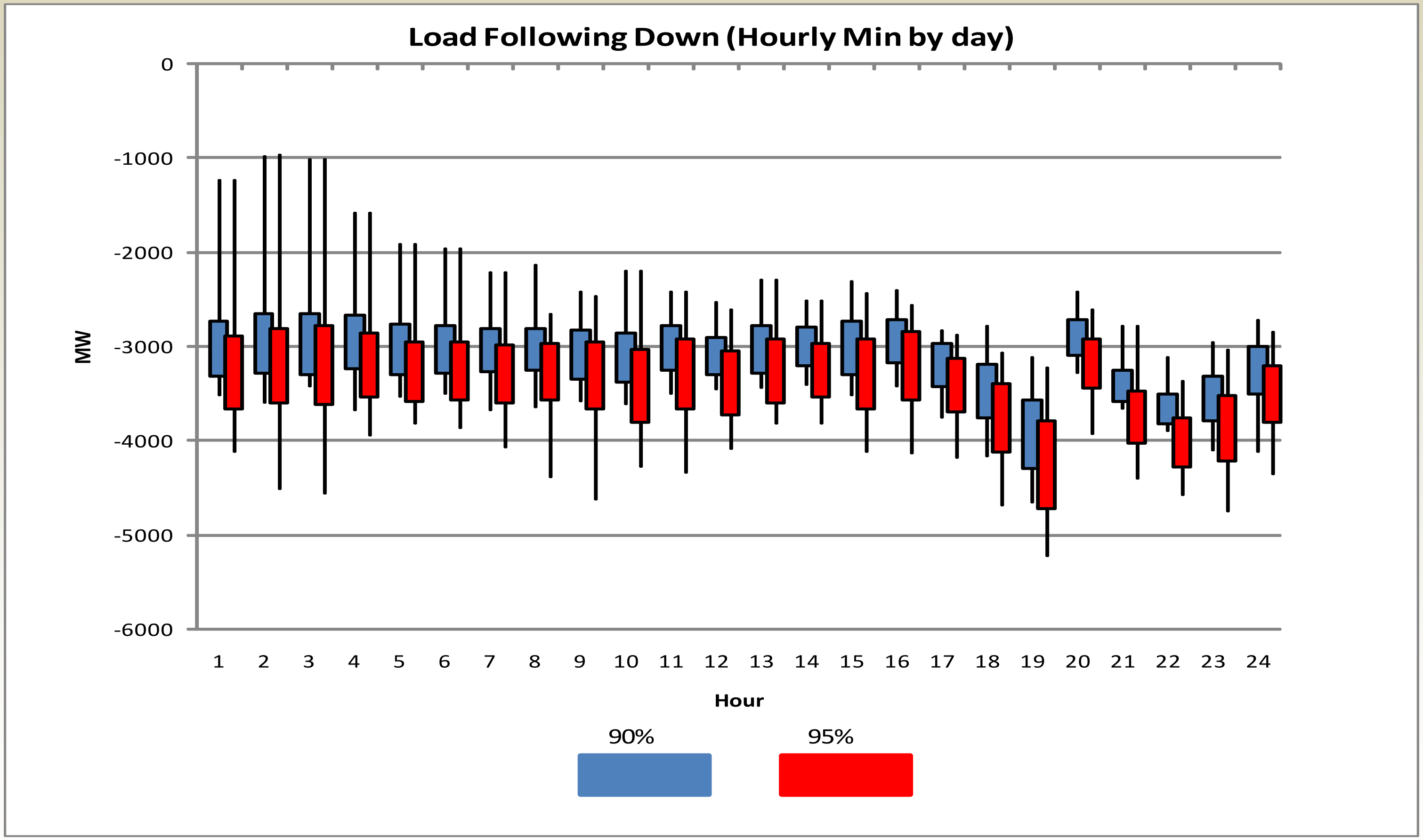
Sensitivity 3: Substitution of Step 1 90th percentile values for 95th percentile values

- Discussed previously in ISO October 22 presentation, slide 19
- Determination to model the 90th percentile values from the Step 1 results for both load-following and Regulation
- Sensitivity still uses seasonal maximum requirements
- Using a lower range of values implies that during events in the extreme range of possible values, either there are more violations of (current) reliability standards or more renewable energy is dumped

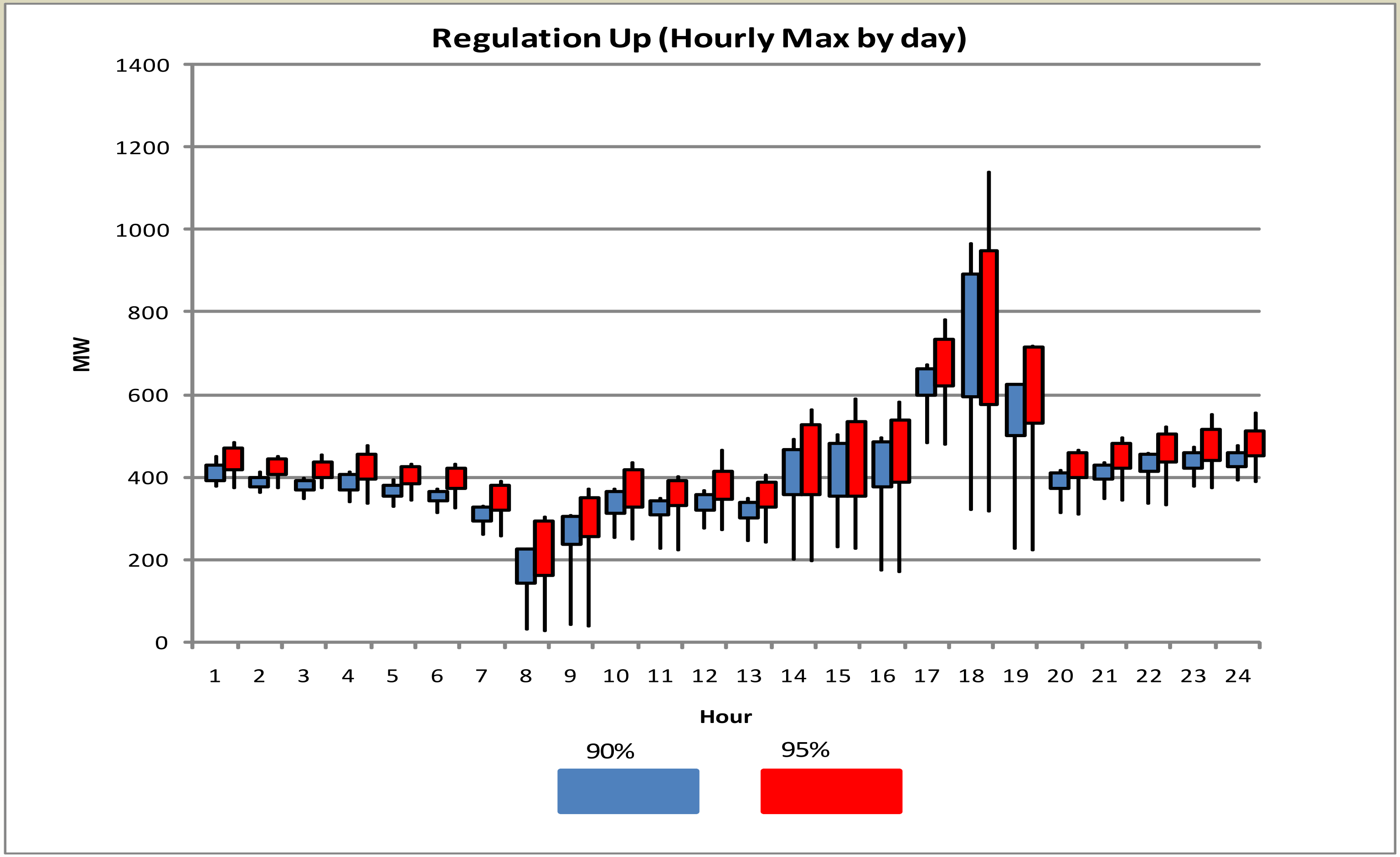
Sensitivity 3 (cont.): Comparison of 90th percentile and 95th percentile values for load-following up



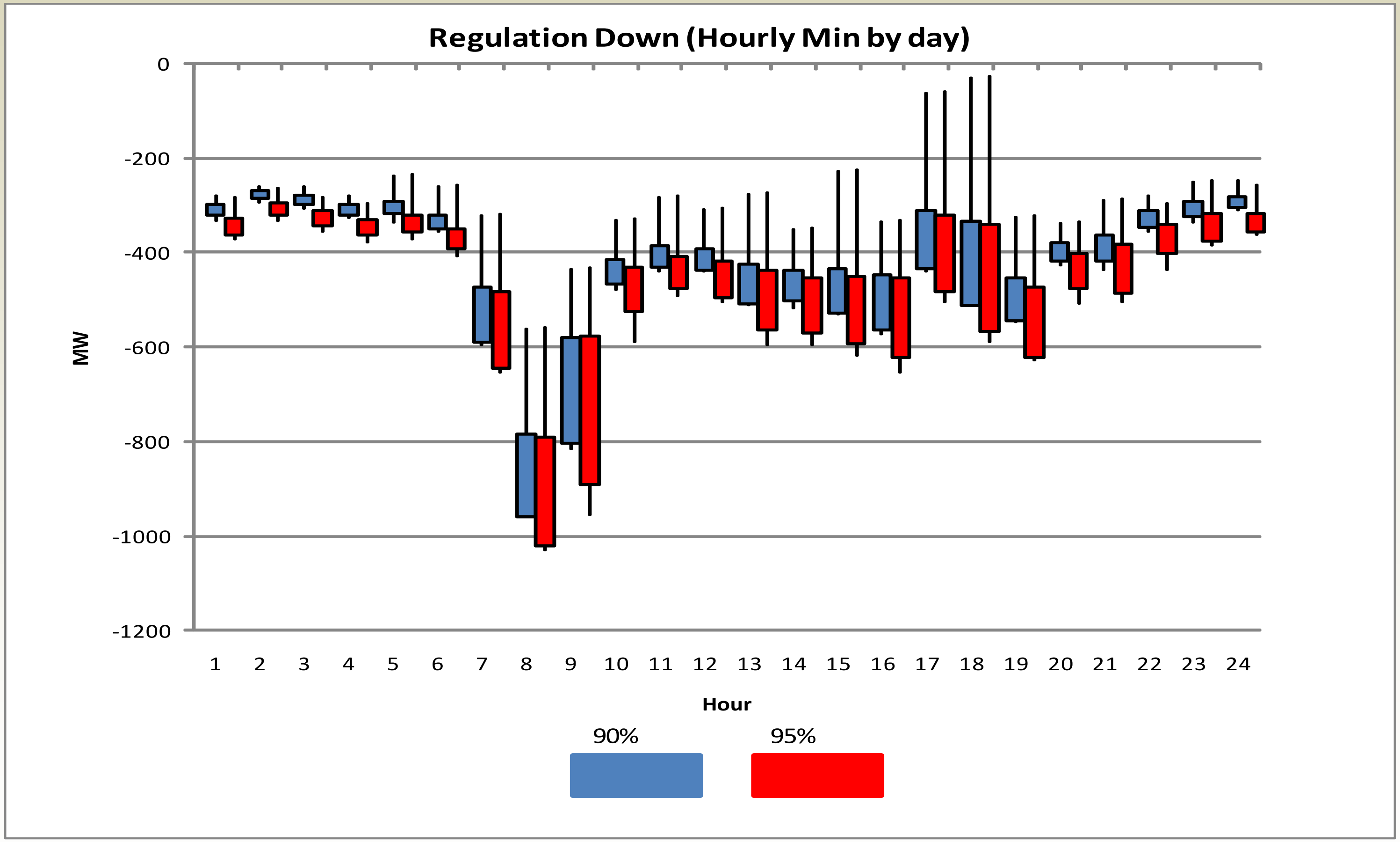
Sensitivity 3 (cont.): Comparison of 90th percentile and 95th percentile values for load-following down



Sensitivity 3 (cont.): Comparison of 90th percentile and 95th percentile values for Regulation Up



Sensitivity 3 (cont.): Comparison of 90th percentile and 95th percentile values for Regulation Down



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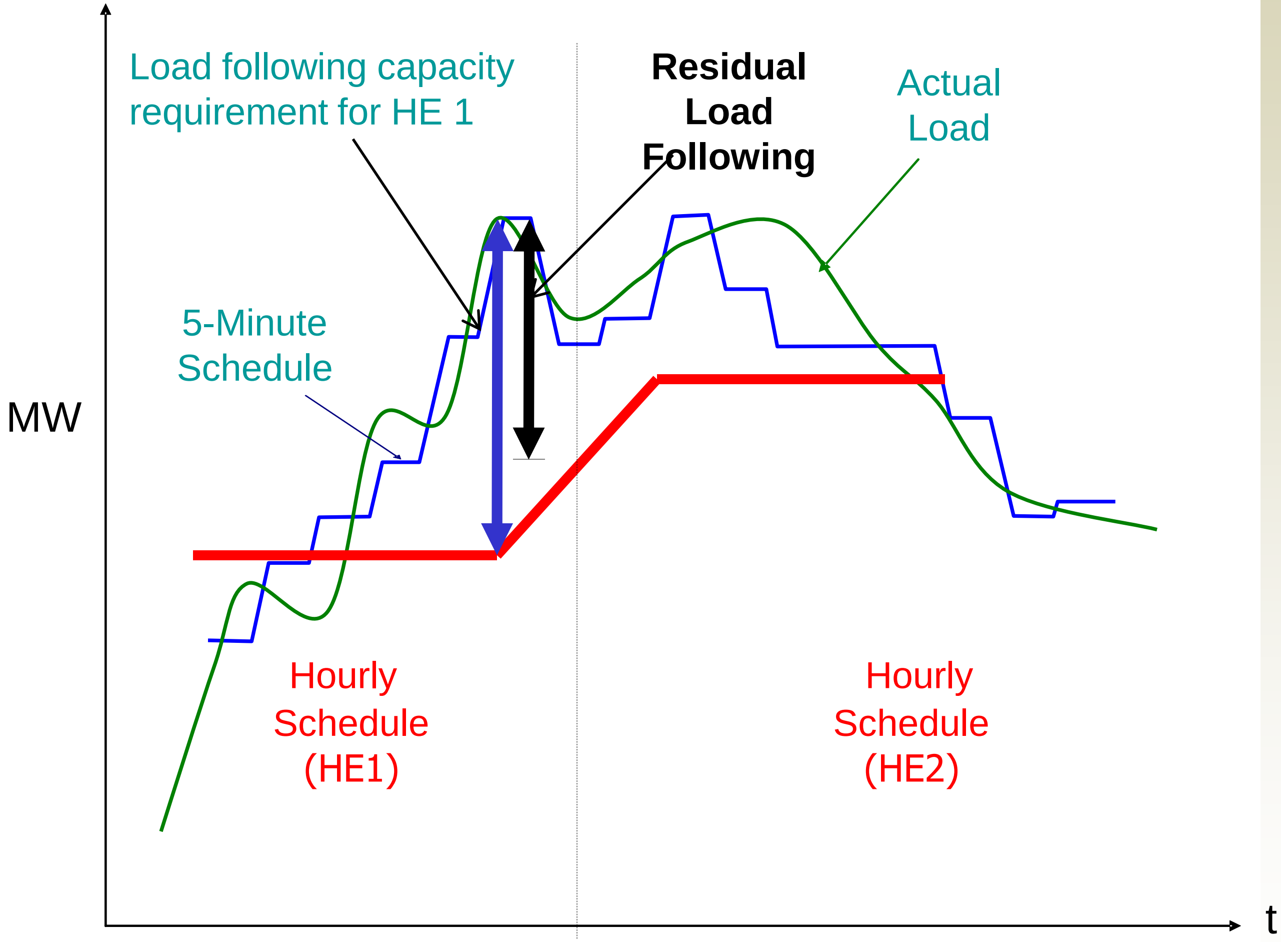
Sensitivity 4: No load-following down requirement

- Discussed previously in ISO October 22 presentation, slides 27-34
- ISO intends to provide sensitivity results with no load-following down requirement modeled
- No results available yet

Sensitivity 5: "Residual" vs. total load-following capacity requirement

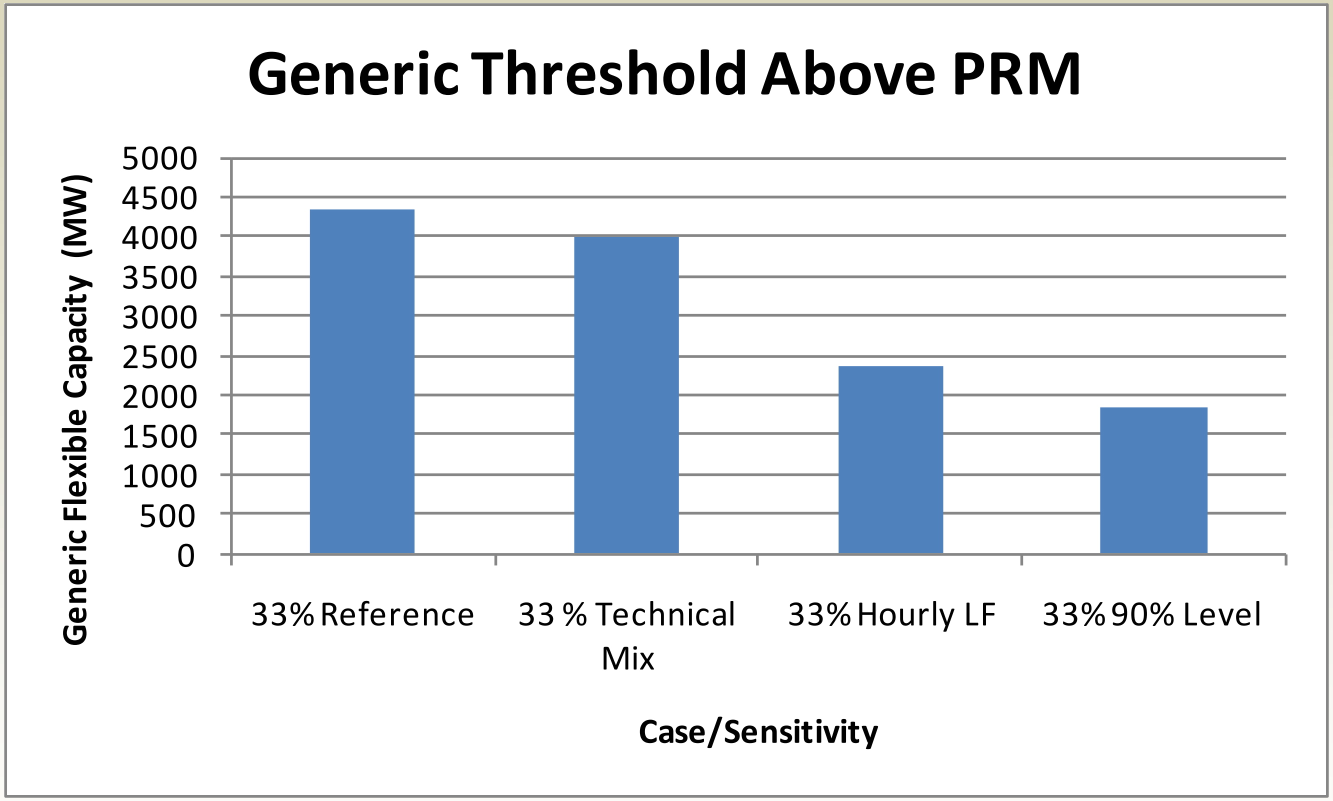
- Discussed previously in ISO October 22 presentation, slides 24-26
- Attempts to reduce the Step 1 load-following requirement by accounting for some degree of the inherent load-following capability of the economic dispatch between any two operating hours
- Diagram on next slide attempts to distinguish total vs. residual capacity requirement for load-following up using one reasonably conservative method
  - Subtract half the inter-hourly ramp from maximum load-following requirement to reflect that schedules will already provide that ramp

Sensitivity 5 (cont.): Diagram of one approach to separating "residual" vs. total load-following up capacity



Note : This figure does not reflect an actual scheduling interval

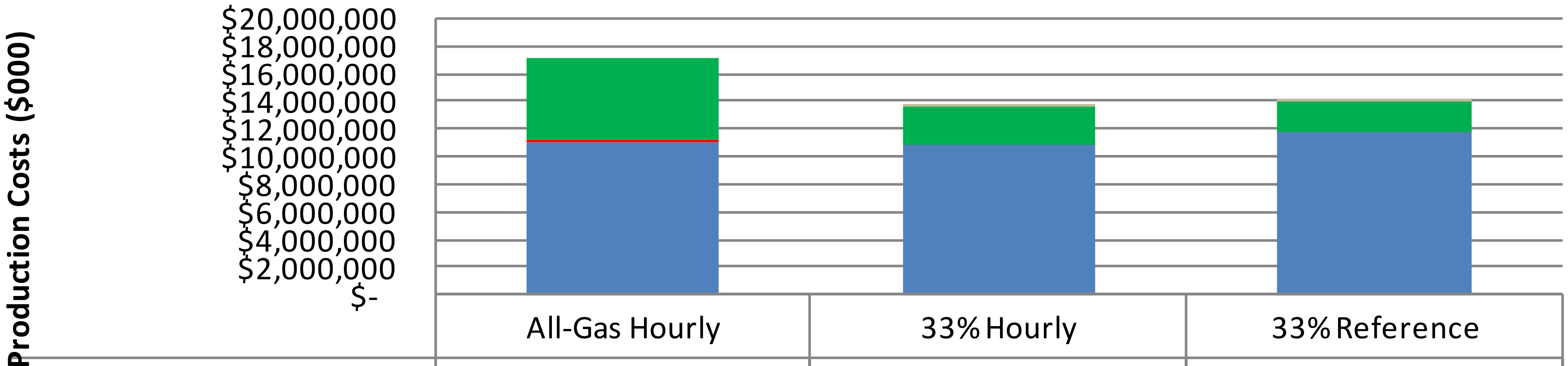
Initial sensitivity results: Determination of capacity needed above PRM, 33% RPS Reference Case with sensitivity results*



* The 33% Technical Mix and 90th percentile result were September 2020 only while the 33% Reference and the 33% hourly load-following requirements were annual runs

Total annual production costs ($) associated with California load (accounting for import/exports), selected sensitivities

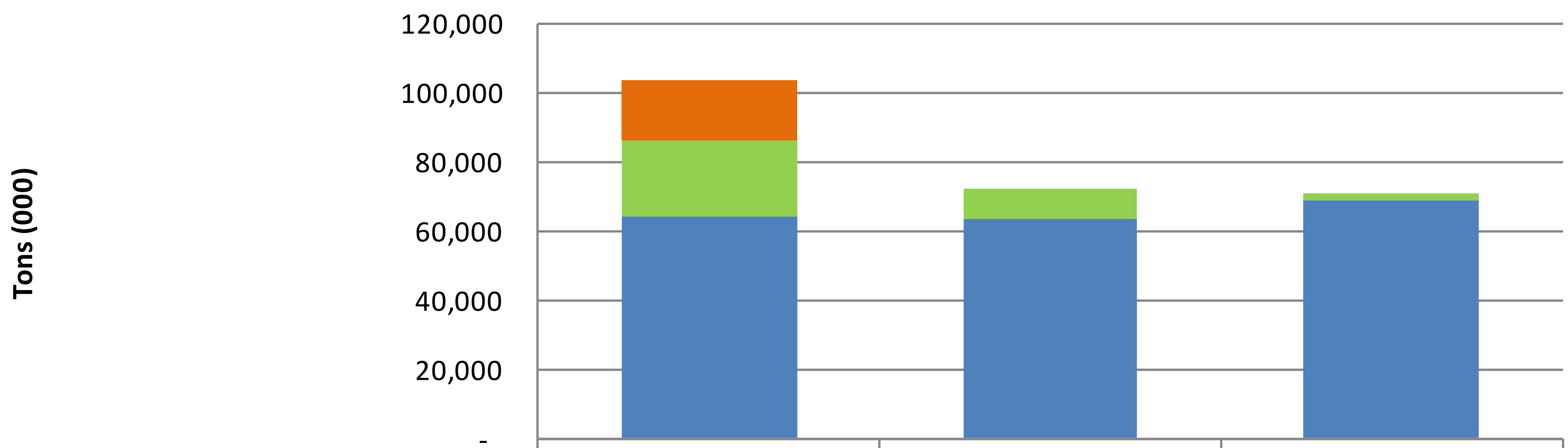
Production Costs to Meet CA Load Accounting for Imports / Exports (Sensitivities)



	All-Gas Hourly	33% Hourly	33% Reference
OOS Non-Generation Costs	$-	$2,750	$2,731
Non-Dedicated	$5,999,546	$2,628,663	$2,124,524
Dedicated	$198,119	$121,463	$101,070
CA Generation Prod Costs	$10,948,208	$10,821,279	$11,709,762

Emissions attributed to meet California load (accounting for Import/Exports), for selected sensitivities and emissions source

Emissions Attributable to Meet CA Load Accounting for Imports / Exports (Sensitivities)



	All-Gas Hourly	33% Hourly	33% Reference
Emissions from Non-Dedicated Import	17,891	-	-
Emissions from Dedicatied Imports	21,775	9,067	2,198
CA Emissions	64,236	63,239	68,615

1. Attribution of emissions for imports is calculated based on the annual net imports assigned an emissions rate of .44Mtons/MWh

Discussion of Results

- Initial findings appear consistent with expectations:
  - Results are sensitive to technology mix
  - Lower levels of additional load-following and regulation reserve capacity in California results in less additional capacity needed and lower in-state production costs and emissions
- Results help clarify relationships between operational requirements, additional capacity needs, and variable costs and emissions
  - Maximum requirements drive determination of additional capacity requirements; reduced requirements provide better estimates of production costs and emissions
- Core scenario assumptions for next round of analysis need to be determined

SECTION 4:
FURTHER ANALYSIS OF FLEET FLEXIBILTY IN 2020

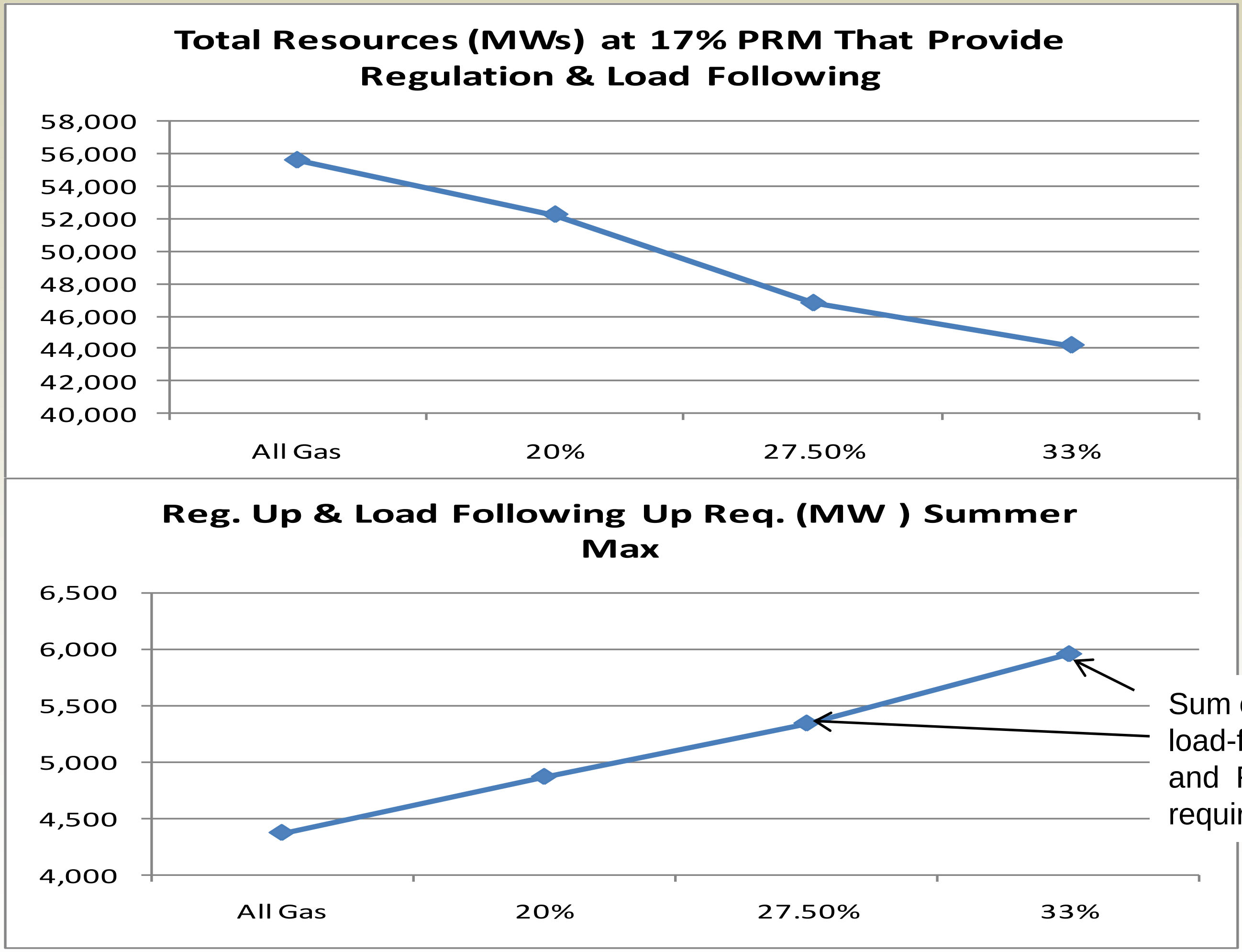
Analysis of generation fleet flexibility in 2020

- ISO October 22 presentation, slides 35-44, provided initial findings on the operational flexibility of the fleet represented in each of the 2020 cases studied
- Stakeholders requested clarifications and comparison to flexibility of current (2010) fleet
- Background:
  - Assumption that significant number of flexible unit retire by 2020 (OTC and others that total 15,701 MW) with only 9,404 MW planned additions
  - Capacity credit given to renewables (NQCs) in PRM build-out substantially increases by 2020: 33% Reference Case credit is 11,654 MW)
  - Clear trend in fewer dispatchable resources with less operational flexibility as integration requirements increase

Analysis of generation fleet flexibility in 2020 (cont.)

- Results presented here provide further perspective on fleet flexibility in the 2020 cases, at PRM and with the added resources needed to meet operational needs
- Results include the flexibility of the existing fleet (2010) for comparison to the flexibility of the resources common to the 2020 cases
- Indices are calculated for each of the cases analyzed, including
  - Sum of all Regulation and load-following ranges for all resources than can provide these capabilities
  - Sum of Regulation capability (that can be provided in 10 minutes) and load-following capability (that can be provided in 20 minutes) by all resources in the fleet

Relationship of fleet flexibility at PRM vs. requirements in 2020 by scenario

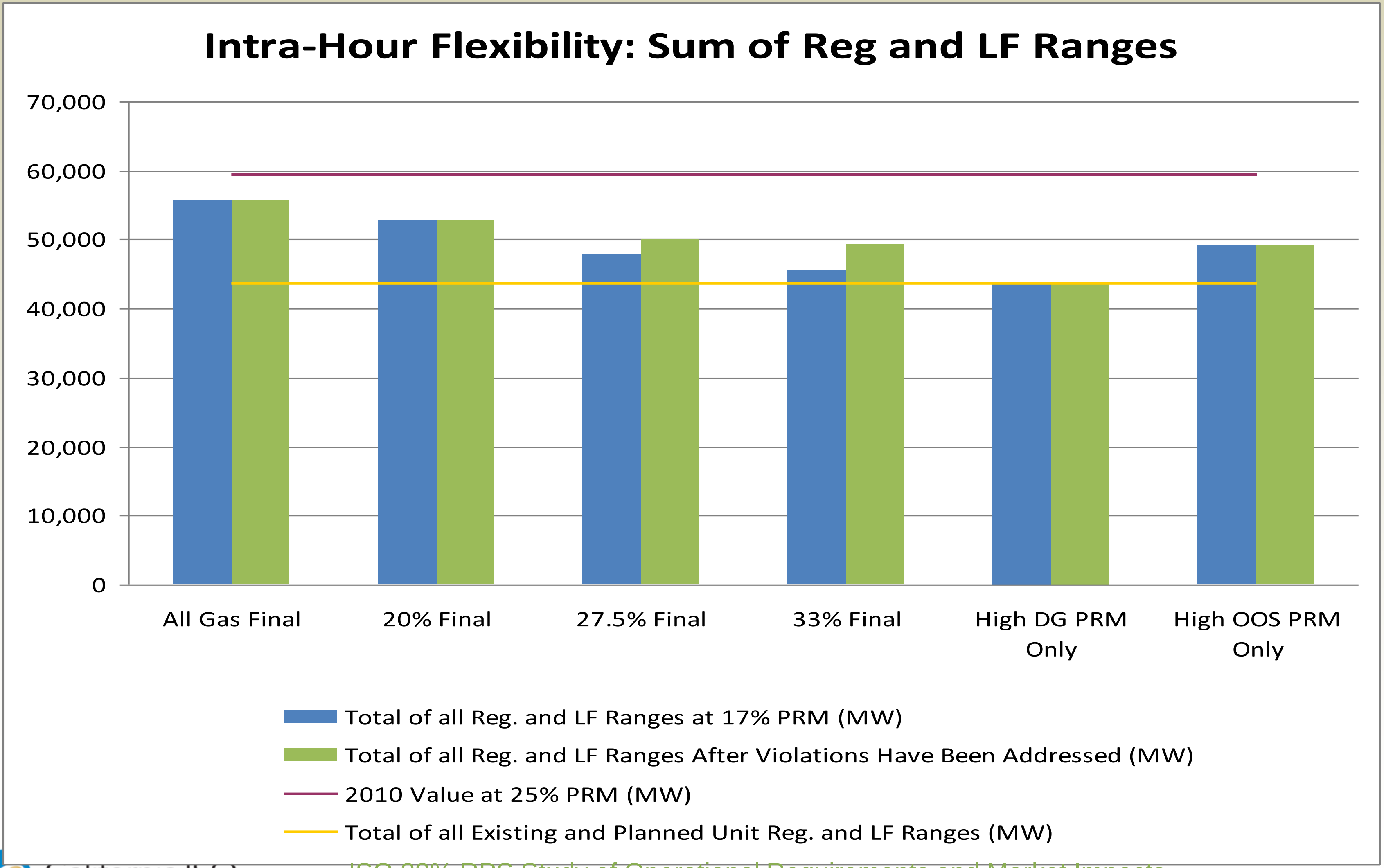


Sum of seasonal max load-following up (MW) and Regulation up (MW) requirements

Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational range

- The following figure shows the fleet's modeled operational range for Regulation and load-following
  - Index is the sum of the ranges for load following and Regulation
  - Load-following range is the maximum output that the resource can provide load following minus the minimum output (in MW)
  - Regulation range is determined in the same manner for resources that provide regulation; Regulation range is normally smaller than load-following range
  - Plot shows index for 2010 based upon the resources that are in operation in 2010 (see ISO 20% RPS study for more details)
  - Plot shows index for those units that are common to all 2020 cases which includes all existing units except those that are retired by 2020 and units that are planned and will be built; does not include generic units added for PRM or integration

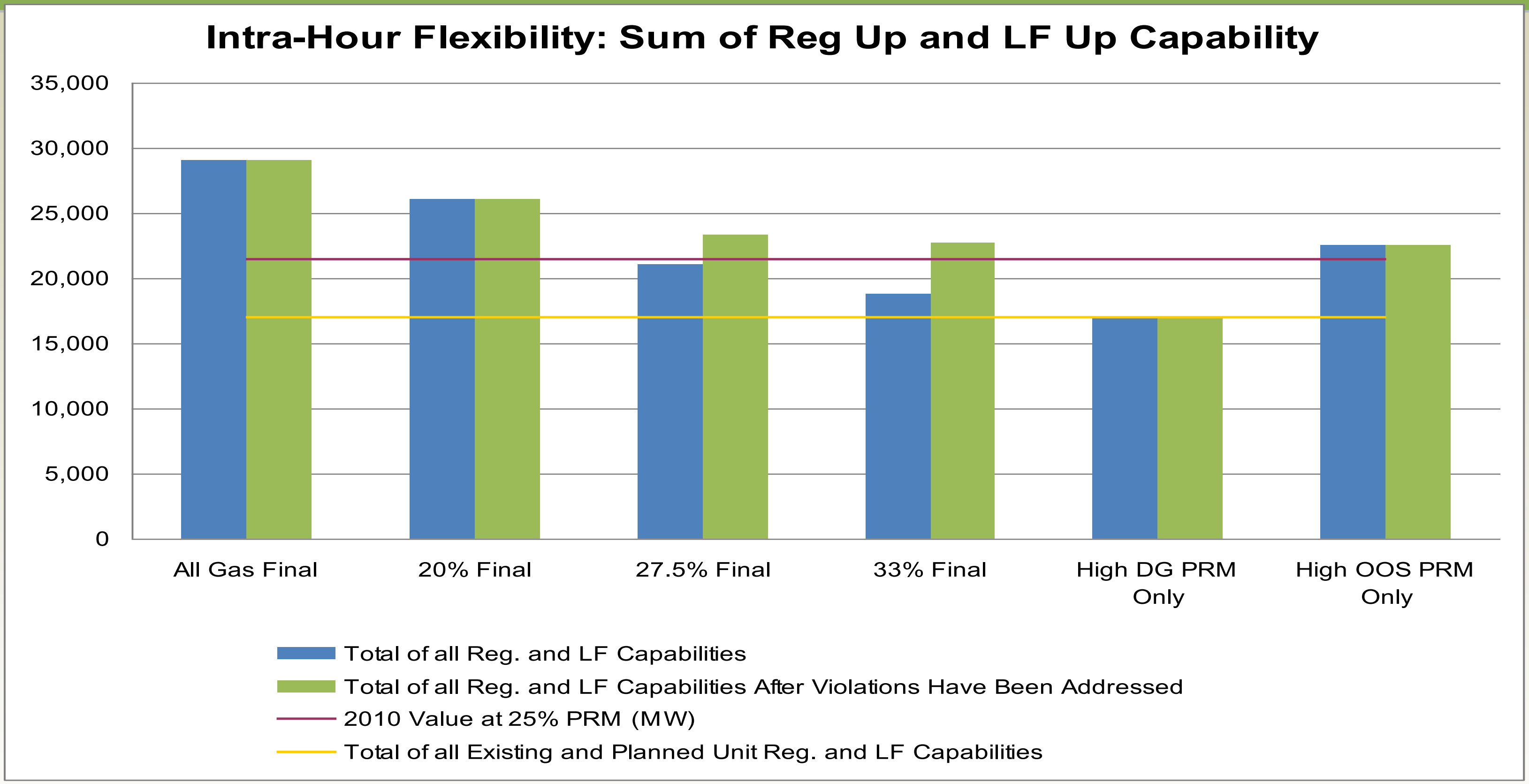
Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational range (cont.)



Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational capacity

- The following figure shows the fleet's modeled capability rated for Regulation and load-following in 2020 and 2010
  - Index is the sum of the capability for Reg. and load-following
  - Regulation capability is the ramp-constrained change in regulation that can be made in 10 minutes (Regulation ramp rate (MW/min) × 10 min.)
  - Load-following capability is the ramp-constrained change in energy that can be made in 20 minutes (Energy ramp rate (MW/min) × 20 min.)
  - Plot shows index for 2010 based upon the resources that are in operation in 2010
  - Plot shows index for those units that are common to all 2020 cases which includes all existing units except those that are retired by 2020 and units that are planned and will be built; does not include generic units

Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational capability (cont.)

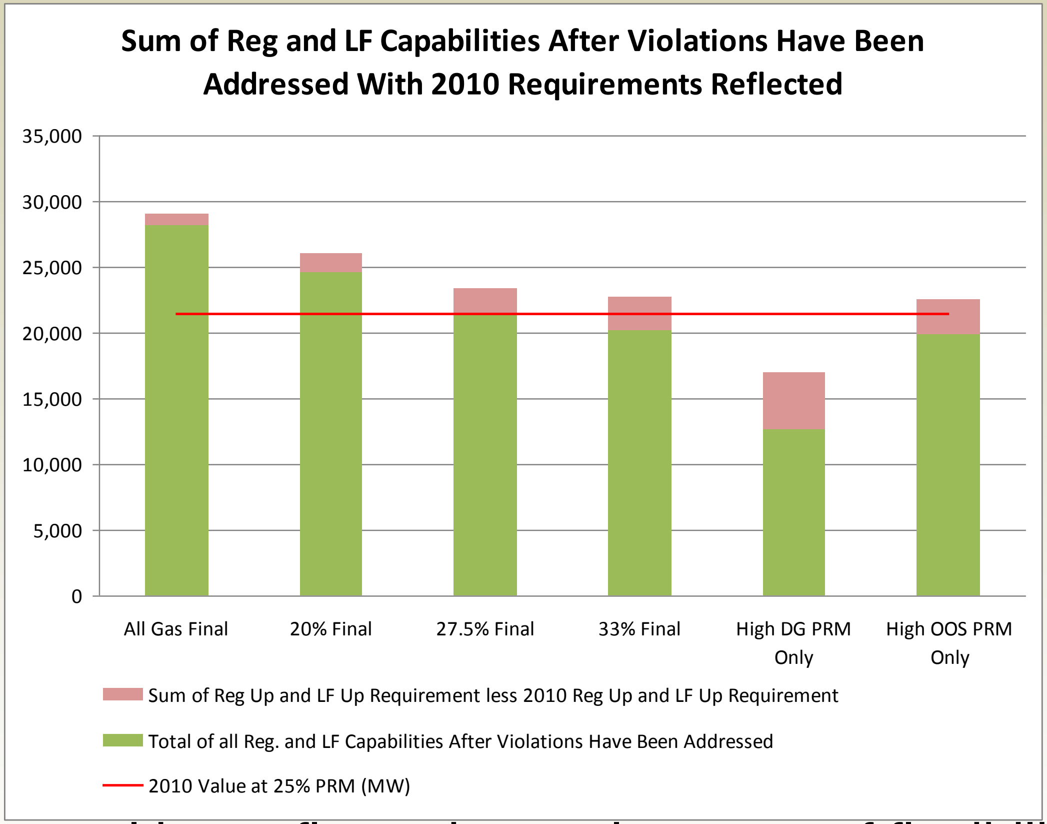


- The blue bar reflects the fleet flexibility of case to meet PRM while the green reflects the fleet flexibility after additions to eliminate violations
- Fleet flexibility decreases as OTC resources are replaced by renewables

Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational capability (cont.)

- Following plot includes the same capability data as the previous slide; for example both slides show that the capability of the fleet in the 33% Reference Case after violations have been addressed is about 24,000 MW
- Following plot shows the portion of this capacity that is needed to meet the requirements in the 33% Reference Case that exceed the requirements in the 2010 Case (Shown in pink)
- The numerical value of this area is 2494 MW (5955 MW – 3461 MW) and represents the amount that the 33% Reference Regulation and load following requirements exceed the 2010 requirements

Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational capability (cont.)



- The total bar reflects the total amount of flexibility fleet to eliminate all requirement violations
- The pink portion of the bar reflects the attribution of the flexibility requirement differences in case from requirements in 2010.

Analysis of generation fleet flexibility in 2020, with comparison to 2010: operational capability (cont.)

- Result
  - Flexibility of the fleet reduces with higher levels of renewables when meeting 17% PRM requirements – Regulation and load-following capability of the fleet in 33% RPS Reference Case are 40% less than in the All Gas Case
  - 33% RPS fleet at 17% PRM has only slightly more flexibility than the system after the OTC retirements and currently planned additions are considered
  - 33% RPS Reference Case fleet has less flexibility than the 2010 fleet before violations are addressed and less after violations have been addressed, when considering the fact that requirements for flexibility increase from 2010 to 2020

Impact of PRM and NQC assumptions on the total resource requirement for renewable integration

- As discussed above, the total number of resources needed to operate the system while eliminating all violations is determined through production simulation
- This total number of resources is independent of the assumptions used for the fleet's PRM level or the NQC for renewables; however, these input assumptions do have an effect on what portion of this total is attributed to meeting the PRM criteria and what portion is attributed to meeting integration needs
- The table in the following slide demonstrates how attributions are affected by these assumptions by showing the impact the number of MW needed changes due to (a) changing PRM requirement by ± 2%, and (b) changing the NQC value for the wind and solar in the 33% Reference Case by ±10%

Impact of PRM and NQC Assumptions on the Attribution of Resources

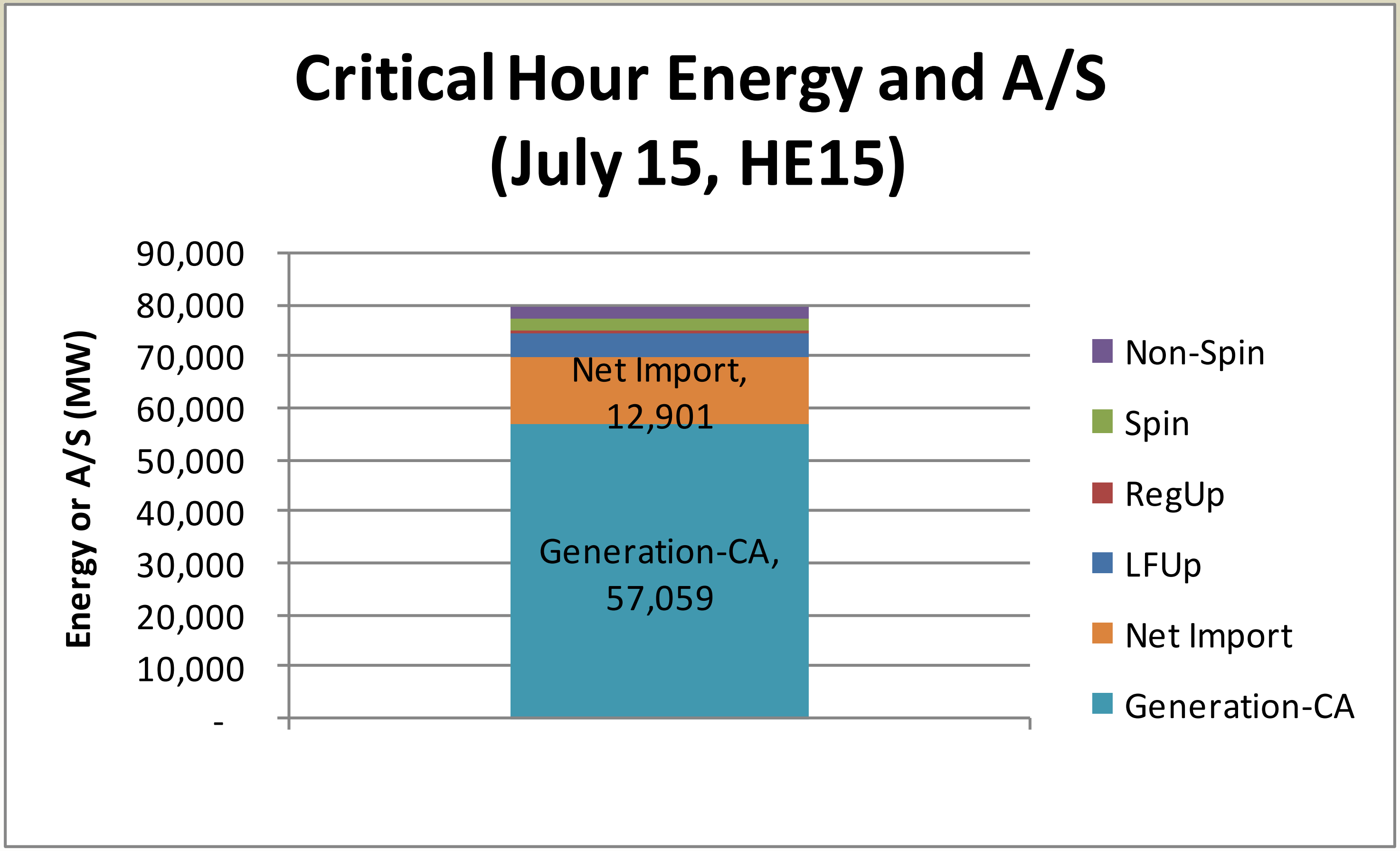
	Lower NQC (x 0.9)	Base Case NQC	Higher NQC (x 1.1)
Higher PRM (19%)	= X-2402	= X-1380	= X-358
Base Case PRM (17%)	= X-1022	X	= X+1022
Lower PRM (15%)	= X+358	= X+1380	= X+2402

Where X = Generics Needed for Integration (MW)
NQCs for Wind and Solar are decreased/increased by 10%

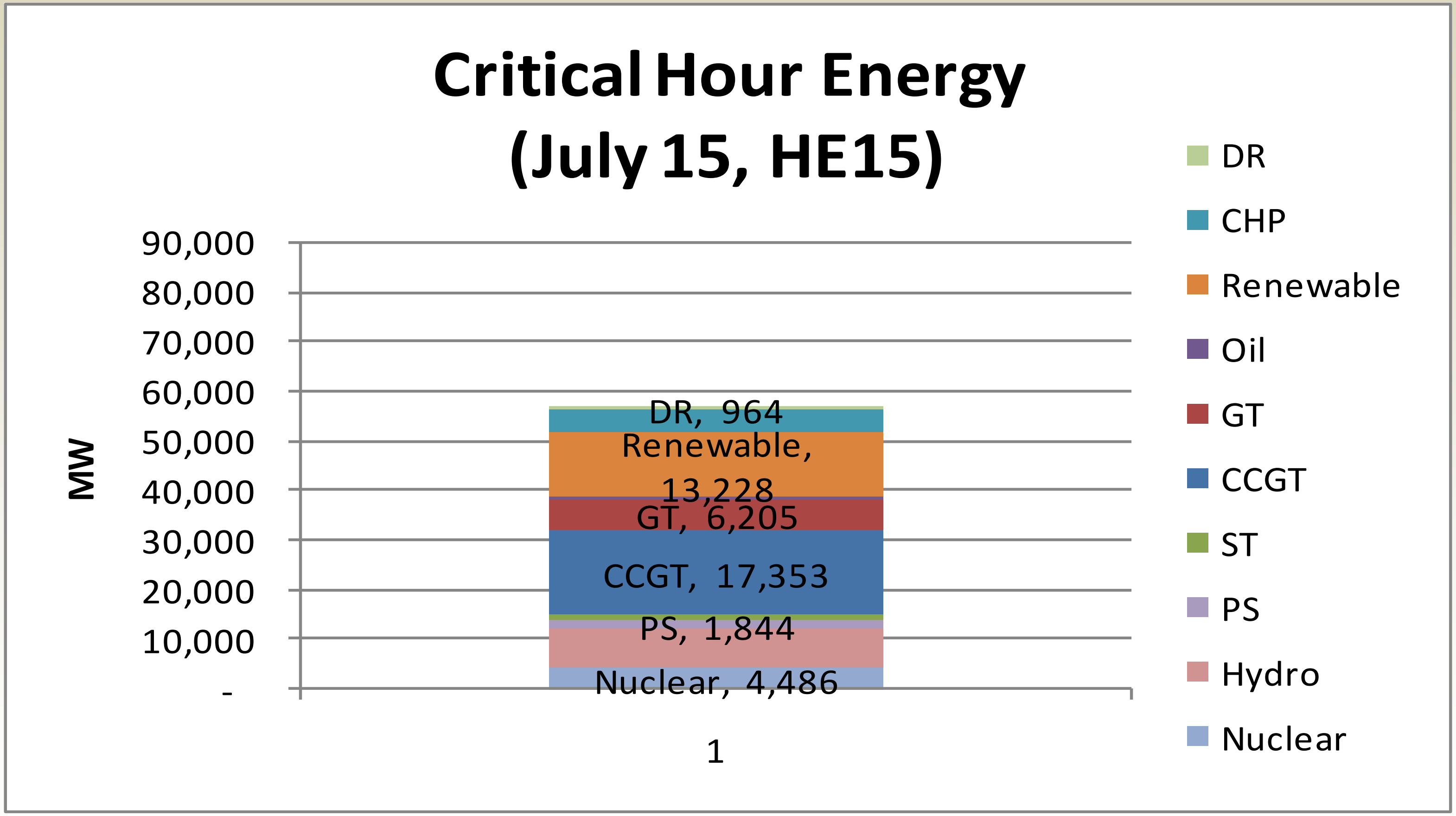
“Drill-down” on resource production on particular days

- Workshop participants requested further analysis of the mix of resources available on particular modeled days and hours
- Can provide insight into the mix of flexible and inflexible resources and relationship of energy and reserves
- Sample results are presented for July 15, Hour Ending (HE)15, for the 33% RPS Reference Case

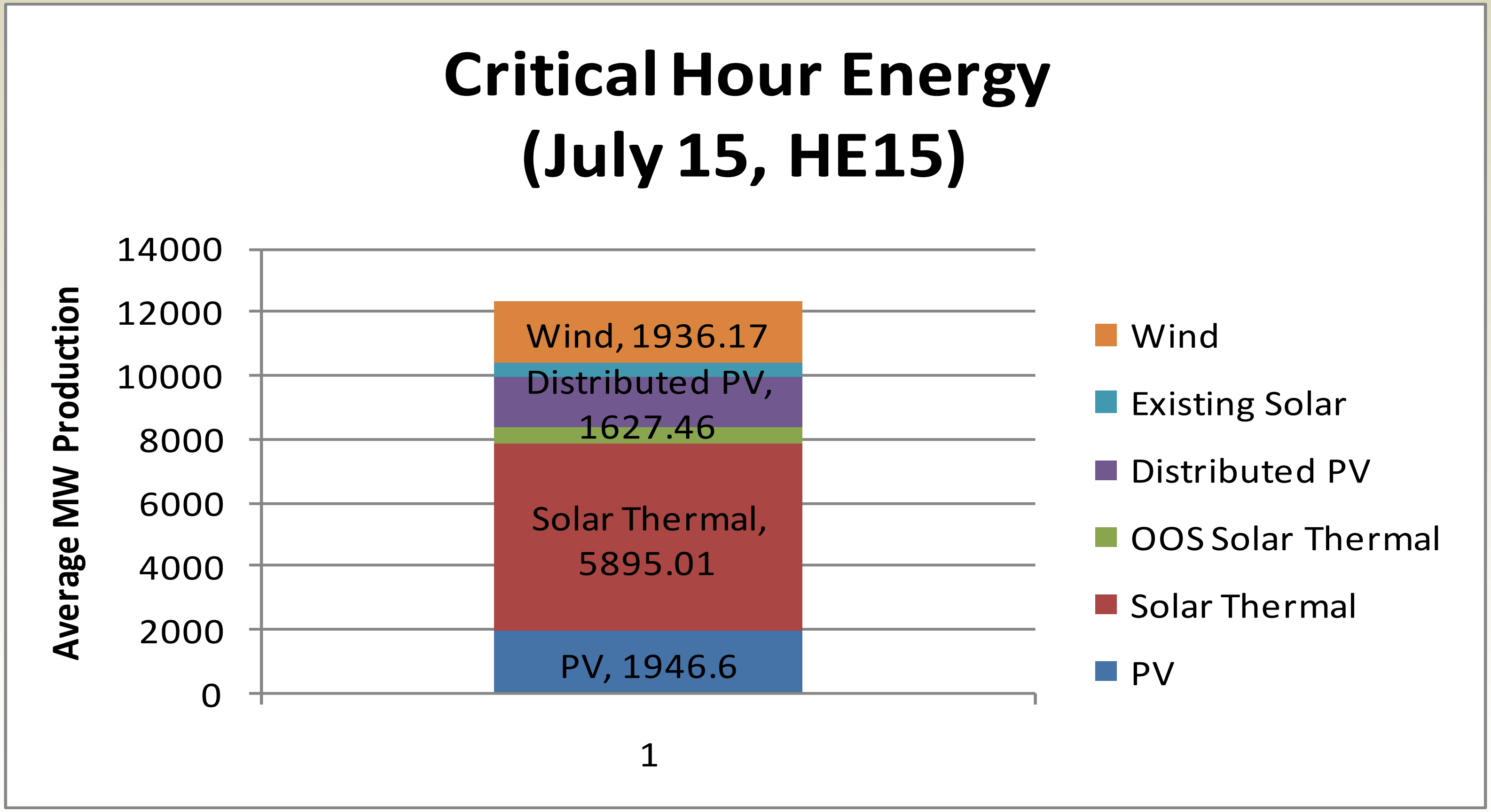
Drill Down – July 15, 2020, HE15



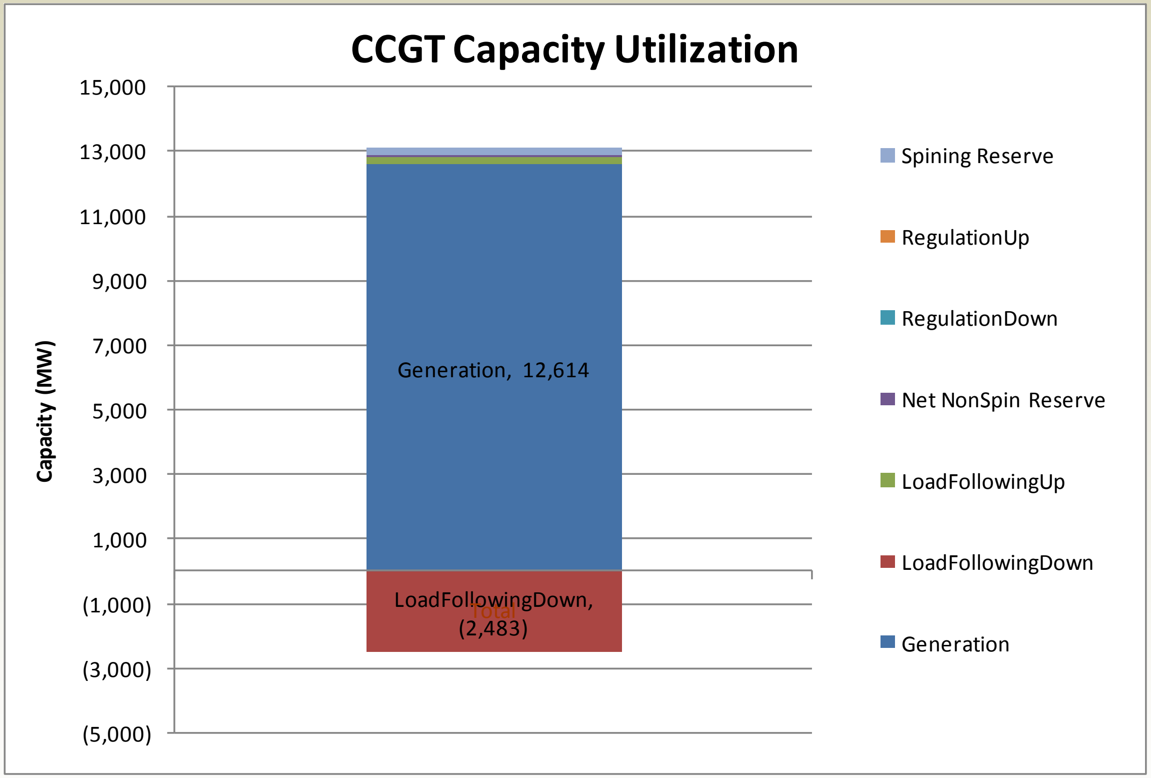
Drill Down – July 15, 2020, HE15



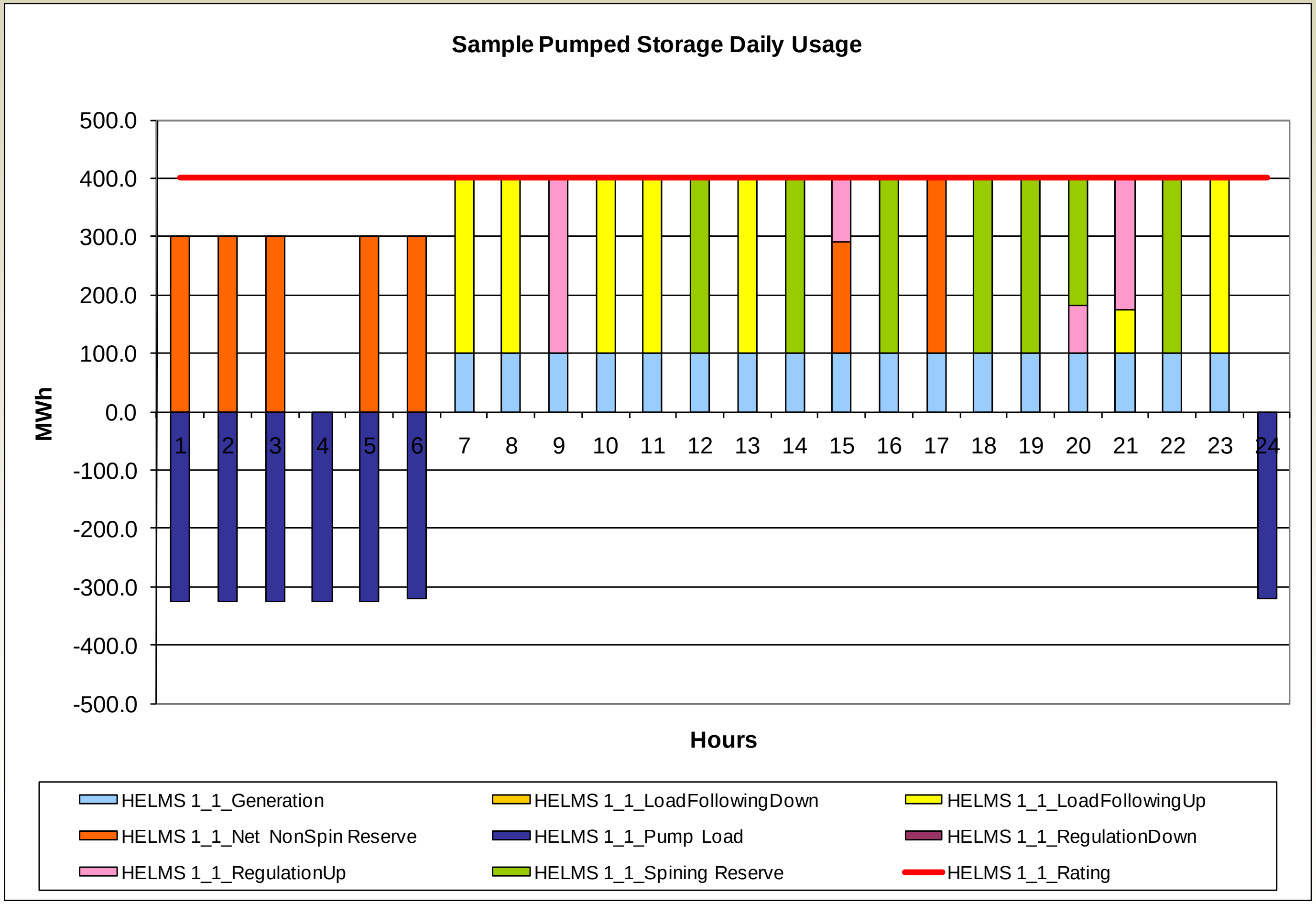
Drill Down – July 15, 2020, HE15 (Solar and Wind Energy Production)



Drill Down – July 15, 2020, HE15 (CCGT Capacity Utilization)



Drill Down – July 15, 2020
(Sample Pump/Storage Utilization)



SECTION 5:
RECOMMENDED NEXT STEPS

Recommended future renewable resource cases

- 33% Expected Trajectory (with reasonable level of imports of renewable incorporated)
- Midpoint renewable trajectory (similar to a 27.5% RPS case) that reflects the expected renewable build-out towards achieving 33% RPS
- Higher DG in 2020 than in the current cases (this case may be important to cover the possibility of larger quantities of DG such as rooftop PV occurs)

Further methodological discussions

- Further analysis of solar variability and forecast error
- Evaluation of the results of sensitivities and decisions on future assumptions
- Lessons learned from ISO 20% RPS study and additional analysis to evaluate those findings
- Other modeling developments

Questions

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